Exhibit A

Proposed Reliability Standards

Exhibit A-1

Proposed Reliability Standard IRO-002-7

A. Introduction

1. **Title:** Reliability Coordination – Monitoring and Analysis
2. **Number:** IRO-002-7
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. Reserved.

M1. Reserved.

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 R2 and R4 and Measures 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. Reserved.				
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 capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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 Variance

A. Regional Variance for the Western Electricity Coordinating Council Region

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) region.

Purpose
To develop a methodology that creates models for performing Operational Planning Analyses and Real-time Assessments.

Applicability
As used in this WECC Regional Variance, Reliability Coordinator is specific to those Reliability Coordinators providing Reliability Coordinator service(s) to entities operating within the Western Interconnection, regardless of where the Reliability Coordinator may be located.

Requirements and Measures

D.A.7. Each Reliability Coordinator shall, in coordination with other Reliability Coordinators, develop a common Interconnection-wide methodology to determine the modeling and monitoring of BES and non-BES Elements that are internal and external to its Reliability Coordinator Area, necessary for providing operational awareness of the impacts on Bulk Electric System Facilities within its Reliability Coordinator Area, including at a minimum: *([Violation Risk Factor: High] [Time Horizon: Operations Planning])*

D.A.7.1. A method for development, maintenance, and periodic review of a Western Interconnection-wide reference model to serve as the baseline from which Reliability Coordinator's operational models are derived;

D.A.7.2. The impacts of Inter-area oscillations;

D.A.7.3. A method to determine Contingencies included in analyses and assessments;

D.A.7.4. A method to determine Remedial Action Schemes included in analyses and assessments;

D.A.7.5. A method to determine forecast data included in analyses and assessments; and

D.A.7.6. A method for the validation and periodic review of the Reliability Coordinator's operational model for steady state and dynamic/oscillatory system response.

M.D.A.7. Each Reliability Coordinator will have evidence that it developed a common Western Interconnection-wide methodology, addressing modeling and monitoring, in coordination with other Reliability Coordinators, that includes the features required in D.A.7.

D.A.8. Each Reliability Coordinator shall use the methodology developed in D.A.7. ([*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*])

M.D.A.8. Each Reliability Coordinator will have evidence that it uses the methodology developed in D.A.7., as required in D.A.8. above.

Compliance

Evidence Retention:

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

R #	Violation Severity Levels for the WECC Regional Variance			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.7.				The Reliability Coordinator did not develop the methodology as required in D.A.7.
D.A.8.				The Reliability Coordinator did not implement the methodology as required in D.A.8.

E. Associated Documents

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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

6	May 9, 2019	Adopted by the NERC Board of Trustees	WECC Regional Variance
7	May 9, 2019	Adopted by the NERC Board of Trustees	Requirement R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of IRO-002-4 in Project 2014-03 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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: (*note*: R1 proposed for retirement in IRO-002-7 as part of Project 2018-03 Standard Efficiency Review Retirements)
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 and IRO-002-7):
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-~~5~~7
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. Reserved.~~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. Reserved.~~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. Reserved.	~~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	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
			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 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	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 unsuccessful test, initiated action to restore the redundant functionality in more than 4	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 functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6	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; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	hours and less than or equal to 4 hours.	hours and less than or equal to 6 hours.	hours and less than or equal to 8 hours.	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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 Variance~~s~~

~~D.~~

A. Regional Variance for the Western Electricity Coordinating Council Region

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) region.

Purpose

To develop a methodology that creates models for performing Operational Planning Analyses and Real-time Assessments.

Applicability

As used in this WECC Regional Variance, Reliability Coordinator is specific to those Reliability Coordinators providing Reliability Coordinator service(s) to entities operating within the Western Interconnection, regardless of where the Reliability Coordinator may be located.

Requirements and Measures

D.A.7. Each Reliability Coordinator shall, in coordination with other Reliability Coordinators, develop a common Interconnection-wide methodology to determine the modeling and monitoring of BES and non-BES Elements that are internal and external to its Reliability Coordinator Area, necessary for providing operational awareness of the impacts on Bulk Electric System Facilities within its Reliability Coordinator Area, including at a minimum: *([Violation Risk Factor: High] [Time Horizon: Operations Planning])*

- **D.A.7.1.** A method for development, maintenance, and periodic review of a Western Interconnection-wide reference model to serve as the baseline from which Reliability Coordinator's operational models are derived;
- **D.A.7.2.** The impacts of Inter-area oscillations;
- **D.A.7.3.** A method to determine Contingencies included in analyses and assessments;
- **D.A.7.4.** A method to determine Remedial Action Schemes included in analyses and assessments;
- **D.A.7.5.** A method to determine forecast data included in analyses and assessments; and
- **D.A.7.6.** A method for the validation and periodic review of the Reliability Coordinator's operational model for steady state and dynamic/oscillatory system response.

M.D.A.7. Each Reliability Coordinator will have evidence that it developed a common Western Interconnection-wide methodology, addressing modeling and monitoring, in coordination with other Reliability Coordinators, that includes the features required in D.A.7.

D.A.8. Each Reliability Coordinator shall use the methodology developed in D.A.7. ([*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*])

M.D.A.8. Each Reliability Coordinator will have evidence that it uses the methodology developed in D.A.7., as required in D.A.8. above.

Compliance

Evidence Retention:

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

R #	Violation Severity Levels for the WECC Regional Variance			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.7.				The Reliability Coordinator did not develop the methodology as required in D.A.7.
D.A.8.				The Reliability Coordinator did not implement the methodology as required in D.A.8.

E. 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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

6	May 9, 2019	Adopted by the NERC Board of Trustees	WECC Regional Variance
7	May 9, 2019	Adopted by the NERC Board of Trustees	Requirement R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

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 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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: (*note*: R1 proposed for retirement in IRO-002-7~~6~~ as part of Project 2018-03 Standard Efficiency Review Retirements)

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 and IRO-002-7~~6~~):
The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Exhibit A-2

Proposed Reliability Standard TOP-001-5

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-5
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. Reserved.

M19. Reserved.

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. Reserved.

M22. Reserved.

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 R18, and Measure M15 through M18 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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 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	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	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	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	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 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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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. Reserved.				
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	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
			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 exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days	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	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	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

R #	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.	redundant functionality in more than 4 hours and less than or equal to 6 hours.	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 at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Authority's primary Control Center, 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 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	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	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	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; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	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 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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	May 9, 2019	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the [Project 2014-03] and [Project 2016-01] pages.

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):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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-001-45
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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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~~R18, and Measure M15 through ~~M19~~ M18 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Operator of its inability to comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 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	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	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,	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,

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	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.	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.	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.	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 required or identified as necessary by the Transmission	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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 any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	for one 30-minute period within that 24-hour period.	minute periods within that 24-hour period.		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.
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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. Reserved.	~~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~~	~~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.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~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 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	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;	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;	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

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 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 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.	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 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 restore the redundant functionality.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R22. Reserved.	~~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.

R #	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	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.			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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	~~TBD~~May 9, 2019	Adopted by Board of Trustees	Requirements R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

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 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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.~~ [Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:

[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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 A-3

Proposed Reliability Standard VAR-001-6

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-6

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

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

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.

M2. Reserved.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the

associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to

the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:
"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. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.						
R3.	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	May 9, 2019	Adopted by the NERC Board of Trustees	Requirement R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R3:

The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area’s needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP’s criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate

granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-~~5~~6

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:** ~~The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~See Implementation Plan.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.~~Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*~~

M2. Reserved. ~~Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.~~

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"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. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.	~~**Real-time Operations, Same-day Operations**~~	~~**High**~~	~~N/A~~	~~N/A~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.~~
R3.	**Real-time Operations, Same-day Operations**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	~~TBD~~May 9, 2019	Adopted by the NERC Board of Trustees	Requirement R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

~~**Rationale for R2:**~~

~~Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.~~

Rationale for R3:

~~Similar to Requirement R2, t~~The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:
The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:
The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2018-03 Standards Efficiency Review Retirements

Applicable Standard(s)

- FAC-008-4 – Facility Ratings
- INT-006-5 – Evaluation of Interchange Transactions
- INT-009-3 – Implementation of Interchange
- IRO-002-7 – Reliability Coordination – Monitoring and Analysis
- PRC-004-6 – Protection System Misoperation Identification and Correction
- TOP-001-5 – Transmission Operations
- VAR-001-6 – Voltage and Reactive Control

Requested Retirement(s)

- FAC-008-3 – Facility Ratings
- FAC-013-2 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- INT-004-3.1 – Dynamic Transfers
- INT-006-4 – Evaluation of Interchange Transactions
- INT-009-2.1 – Implementation of Interchange
- INT-010-2.1 – Interchange Initiation and Modification for Reliability
- IRO-002-6 – Reliability Coordination – Monitoring and Analysis
- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Readability Margin Calculation Methodology
- MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
- MOD-028-2 – Area Interchange Methodology
- MOD-029-2a – Rated System Path Methodology
- MOD-030-3 – Flowgate Methodology
- PRC-004-5(i) – Protection System Misoperation Identification and Correction
- TOP-001-4– Transmission Operations
- VAR-001-5– Voltage and Reactive Control

Requested Withdrawal

- MOD-001-2 – Available Transmission System Capability

Applicable Entities

See subject standards.

Background

In 2017, NERC initiated the Standards Efficiency Review. The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. Following the completion of the first phase of work, the Standards Efficiency Review Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- withdraw a standard, MOD-001-2, that is currently pending approval by applicable governmental authorities.

General Considerations

For Reliability Standards that are proposed to be retired in their entirety (i.e., no new standard version is proposed), this Implementation Plan provides that the retirement shall become effective immediately upon regulatory approval.

For Reliability Standards that are revised to remove requirements, the revised standards will become effective on the first day of the first calendar quarter that is three (3) months after applicable regulatory approval. This implementation timeframe reflects consideration that entities may need time to update their internal systems and documentation to reflect the new standard version numbers.

Effective Date

Reliability Standards FAC-008-4, INT-006-5, INT-009-3, IRO-002-7, PRC-004-6, TOP-001-5, and VAR-001-6

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 (3) 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 (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standards FAC-008-3, INT-006-4, INT-009-2.1, IRO-002-6, PRC-004-5(i), TOP-001-4, and VAR-001-5

The Reliability Standard shall be retired immediately prior to the effective date of the revised standard in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standards FAC-013-2, INT-004-3.1, INT-010-2.1, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-020-0, MOD-028-2, MOD-029-2a, and MOD-030-3

The Reliability Standard shall be retired on the effective date of the applicable governmental authority's order approving retirement of 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 be retired on the date the standard is retired by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Exhibit D

Analysis of Violation Risk Factors and Violation Severity Levels

Exhibit D-1

Proposed Reliability Standard IRO-002-7

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard IRO-002-7. 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.

VRF Justification for IRO-002-7, Requirement R2
The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R3
The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R4
The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R5
The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R6
The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R2
The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R3
The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R4
The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R5
The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R6
The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

Exhibit D-2

Proposed Reliability Standard TOP-001-5

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard TOP-001-5. 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.

VRF Justification for TOP-001-5, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R6

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R7

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R8

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R9

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R10

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R2
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

Exhibit D-3

Proposed Reliability Standard VAR-001-6

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard VAR-001-6. 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.

VRF Justification for VAR-001-6, Requirement R1

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R3

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R4

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R5

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R6

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R1

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R3

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R4

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R5

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R6

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

Exhibit E

Technical Rationale

Project 2018-03 - Standards Efficiency Review Retirements

Technical Justifications

Background:
The North American Electric Reliability Corporation (NERC) Project 2018-03 – Standards Efficiency Review (SER) Retirements, was established for the Standard Drafting Team (SDT) to evaluate each recommendation for retirement identified in the Standard Authorization Request (SAR).

The Reliability Standards have their origins in the voluntary consensus Operating Guides and Planning Standards. These original documents were modified into what we currently know as the "Version 0" standards. The objective of the added granularity to the requirements was to support the reliable operation of the Bulk Electric System (BES). These requirements were prescriptive, and meant to provide an industry-wide approach to achieving the reliability objectives of the standards. In the last 10 years, the industry has matured and adopted compliance through the Reliability Standards, and the continuance of the added granularity of the requirements do not contribute to the efficiency and effectiveness of Reliability Standards.

In 2010, NERC determined that absolute, "do exactly as the standard dictates" requirements, in some cases, did not satisfy the reliability goal and required the entity to perform specific actions to be compliant, while not effectively adding to the overall reliability goal. NERC then embarked on a shift in the standards paradigm to what is now known as 'results-based standards,' wherein the standards specify what reliability results from the requirements, while affording entities flexibility in achieving those results. The development guidance, provided by NERC, can be found at the following link:

https://www.nerc.com/pa/Stand/Resources/Documents/Results-Based_Reliability_Standard_Development_Guidance.pdf

Many of the requirements that the Project 2018-03 SDT are proposing to retire in this project pre-date the maturity of the results-based standards paradigm. As a result, those requirements are overly prescriptive and often express the same obligation in several standards and requirements.

Purpose:
The purpose of the Technical Justification Document is to assist in the understanding of the technical rationale associated with each recommendation for retirement identified in the SAR.

Technical Justifications for Phase I of Project 2018-03 Standards Efficiency Review - Retirements

BAL-005-1, Requirements R4 and R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain

Rationale
The SDT determined these requirements should be retained for the following reasons:

Requirements R4 and R6 of BAL-005-1 are requirements specific to the calculation of the Area Control Error (ACE). TOP-010-1(i) Requirement R2 covers ACE with the wording of "…analysis functions and Real-time monitoring…" but does not cover specifics, such as: quality flags for missing or invalid data that is part of BAL-005-1, Requirement R4, or the accuracy of scan rates that is part of BAL-005-1, Requirement R6.

In TOP-010-1(i), Requirement R2 (revised from TOP-010-1) covers the calculation and monitoring of ACE; however, the language: "Each Balancing Authority (BA) shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring," is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) Requirement R4 states: "The BA shall make available to the operator information associated with reporting ACE including, but not limited to, quality flags indicating missing or invalid data." Requirement R6 of BAL-005-1 states: "Each BA that is within a multiple BA Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each BA area." Both of these requirements are specific to identifying missing or invalid data plus scan rates, not just the quality of the Real-time data.

The SER Phase I team will communicate with the SER Phase II team regarding Requirements R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i), Requirement R2, that would satisfy the missing or invalid data plus scan rates. If the SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be candidates for retirement within that project or a future project.

COM-002-4, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding, and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005-2 would not meet the NERC Board of Trustees (BOT) November 7, 2013 Resolution to mandate training, that the SDT include a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity, and any subsequent training can be covered in PER-005-2, or through the operator feedback loop as determined by the entity.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2, Requirement R2 that would satisfy the training requirements specific to training on communications protocols. If the SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirement R2 of COM-002-4 may be a candidate for retirement within that project or a future project.

EOP-005-3, Requirement R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes; however, it is does not specifically provide for System restoration training. In PER-005-2, the requirement to provide System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to System restoration from PER-005-1 was, in part, based on the existence of the former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide System restoration training to operating personnel in any of the Reliability Standards.

A specific requirement for System restoration training should be maintained because, while a System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the SER Phase II team regarding Requirement R8 of EOP-005-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to System restoration training. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R8 of EOP-005-3 may be a candidate for retirement within that project or a future project.

EOP-006-3, Requirement R7
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes; however, it is does not specifically provide for System restoration training. In PER-005-2, the requirement to provide System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to System restoration from PER-005-1 was, in part, based on the existence of former Requirement R9 in EOP-006-2

(Requirement R7 of EOP-006-3). If Requirement R7 in EOP-006-3 is removed, then there will not be any requirements to provide System restoration training to operating personnel in any of the Reliability Standards.

A specific requirement for System restoration training should be maintained because, while a System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the SER Phase II team regarding Requirement R7 of EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to System restoration training. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R7 of EOP-006-3 may be a candidate for retirement within that project or a future project.

FAC-008-3, Requirements R7 and R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1, Requirement R2, the Transmission Owner (TO) and Generator Owner (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1, and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data includes facility ratings as inputs to System Operating Limits (SOL) monitoring. IRO-010-2, Requirement R3, and TOP-003-3, Requirement R5, require that the TO and the GO to respond to the RC's and the TOP's requests.

FAC-013-2 Requirements R1, R2, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

The requirement for PCs to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Individual PCs develop their own methodologies that may be disparate from each other.
- Impacted functional entities, such as the TP, do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable System performance is.
- Entities that receive the methodology or assessment results are not obligated to use or consider the information in their assessments.
- Requirement R4 only requires the assessment be performed for one year in the Near-Term Transmission Planning Horizon. The PC can arbitrarily choose this year, and the analysis does not guarantee transmission service that is necessary for System reliability.

Assessing transfer capability in the planning horizon is a method to test the robustness of the System. Robustness testing of a System is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment of it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by the Federal Energy Regulatory Commission (FERC) in 2014.

INT-004-3.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale

The SDT determined this standard should be retired for the following reasons:

INT-004-3.1 may be retired since it satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice.' Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity (PSE), has been removed from the list of NERC Functional Entities, supporting the market-based observations herein. Requirement R3 specifically refers to "Pseudo-Ties that are included in the North American Energy Standards Board (NAESB) Electric Industry Registry," reinforcing the tie to the NAESB Wholesale Electric Quadrant (WEQ) Business Practice Standards.

INT-006-4, Requirements R3.1, R4, and R5
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these requirements should be retired for the following reasons:

INT-006-4, Requirement R3 Part 3.1 can be retired under Paragraph 81, Criterion A. There is no substantive impact on reliability with requiring the RC to be notified when a Reliability Adjustment Arranged Interchange has been denied.

INT-006-4, Requirement R4 can be retired under Paragraph 81, Criteria A and B7. Covered in NAESB e-Tagging specifications, Section 1.6.3.1 and Section 1.3, Request State. This requirement outlines the conditions that must exist for an Arranged Interchange to transition to Confirmed Interchange. NAESB Electronic Tagging Specification Section 1.6.3.1 and Section 1.3, Request State, stipulate these exact requirements. INT-006-4, Requirement R4 is being recommended for retirement. The requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-006-4, Requirement R5 can be retired under Paragraph 81, Criteria A and B7. This is covered in NAESB e-Tagging specifications, Section 1.6.4. This requirement outlines who is notified when the transition to Confirmed Interchange occurs. NAESB Electronic Tagging Specification, Section 1.6.4, stipulate these exact requirements. INT-006-4, Requirement R5, is being recommended for retirement; the requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-009-2.1, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this requirement should be retired for the following reasons:

This requirement can be retired under Paragraph 81, Criterion B7. INT-009-2.1, Requirement R2, is redundant with the approved NERC Reliability Standard BAL-005-1, Requirement R7.

INT-010-2.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

The opportunity exists to retire Reliability Standard INT-010-2.1 in its entirety.

INT-010-2.1, Requirement R1: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R1 for retirement. More stringent tagging requirements already

exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R2: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R2 for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-8. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R3: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R3 for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5, Requirements R1, R4 and R6:
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R1, Retain Requirements R4 and R6
Rationale
The SDT determined that Requirement R1 should be retired for the following reasons:

Requirement R1 of IRO-002-5 is redundant to other requirements in the Interconnection Reliability Operations and Coordination (IRO) family of standards. Requirement R1 and data exchange for the Operational Planning Assessment (OPA) is inherent to Requirement R2 that has a higher Violation Risk Factor (VRF) and is tied to the OPA in IRO-010-2, Requirement R3. The requirement is a control for aiding compliance with IRO-008-2, Requirement R1, related to the performance of an OPA, and it is duplicative to Requirement R3 in IRO-010-2. The purpose statement of IRO-010-2 is for the RC: "To prevent instability, uncontrolled separation, or Cascading outages the adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area." The Purpose statement of IRO-008-2 is for the RC to: "Perform the analysis to prevent instability, uncontrolled separation, or Cascading" and with the data collected per IRO-010-2. The data exchange capabilities are indicated in IRO-010-2, Requirement R3, which includes BA's and TOPs, and IRO-008-2, Requirement R1, requires the RC to perform the OPA, which makes IRO-002-5, Requirement R1, redundant with the aforementioned standards and requirements.

IRO-010-2 (R1) requires the RC to identify the data it needs to perform its OPA's, Real-time monitoring, and Real-time Assessments. Requirement R1 clearly states what is required, 1.1 A list of data and information needed by the RC to support its OPA, Real-time monitoring, and Real-time assessments including non-BES data and external network data, as deemed necessary by the RC, 1.2 Provisions for notification of current Protection System and Special Protection Systems status or degradation that impacts System Reliability, 1.3 A periodicity for providing data, 1.4 The deadline by which the respondent is to provide the indicated data. Requirement R2 clearly states, "The RC shall distribute its data specifications to entities that have data required by the RC's OPAs, Real-time monitoring, and Real-time Assessments. Requirement R3 gets to the core of the data exchange capabilities "Each RC, BA, GO, GOP, Load-Serving Entity (LSE), TOP, TO, and Distribution Provider (DP) receiving a data specification in

Requirement R2 shall satisfy the obligations of the documented specifications using 3.1 A mutually agreeable format, 3.2 A mutually agreeable process for resolving data conflicts, 3.3 A mutually agreeable security protocol. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the OPA. Finally, Measure M1 for IRO-002-5, Requirement R1, states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the IRO-002-5, Requirement R1, is not needed to support reliability and can be retired.

The SDT determined that Requirements R4 and R6 should be retained for the following reasons:

IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

The requirements in IRO-010-2 shall satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via a redundant/secure communications, such as Inter Control Center Communication Protocol (ICCP), email, voltage schedules, outage scheduling that all RCs, BAs and TOPs use to exchange the required data.

IRO-008-2, Requirement R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

Although IRO-008-2, Requirement R6, appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6, is not being sought during this phase of the project.

IRO-014-3, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The reliability objective of “notification” is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (Requirement R1, Part 1.1); this ensures RC operations are coordinated to maintain reliability of the BES. As such, a separate requirement for ensuring notifications are made to impacted RCs is duplicative. However, the IRO-014-3, Requirement R1, time horizon would need to be revised to a time horizon of “Real-time” if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3, is not being sought during this phase of the project.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R3 of IRO-014-3 to determine if there is opportunity for revision to IRO-014-3, Requirement R1, that would satisfy the revision of the time horizon to “Real-time.” If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R3 of IRO-014-3 may be a candidate for retirement within that project or within a future project.

IRO-017-1, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3, for retirement.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TLP-001-4 that would satisfy the adding of the RC as a named recipient. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R3 of IRO-017-1 may be a candidate for retirement within that project or within a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3, MOD-001-1a and proposed MOD-001-2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these standards should be retired for the following reasons:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as e-Tags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time System operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the System to its actual reliability limits.

MOD-002-1: Entities are not required to determine Total Flowgate Capability (TFC), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), Available Transfer Capability (ATC), Capacity Benefit Margin (CBM), or Transmission Reliability Margin (TRM), therefore; this is a conditional obligation, and there is no requirement that entities coordinate their methodologies. A reliability-based requirement

would establish obligations to ensure consistency between entities' methodologies. These requirements are administrative in nature and have no performance measure.

Additionally, TOPs and/or TSPs are not obligated in any fashion to determine TFC, TTC, AFC, ATC, CBM or TRM, nor are any criteria established for these quantities. Therefore, the requirements here require that entities that use an optional mechanism with no related criteria provide a methodology document and associated implementation documents, with no criteria as to what those documents must include, rather than just their "methodology." That reinforces that these are all administrative documents with little (if any) reliability benefit.

Further, Requirement R3 establishes that the TSP develops CBM for the benefit of the LSE, which has been removed from the list of NERC Functional Entities.

Finally, Requirements R5 and R6, through their clear and focused references to Open Access Same-Time Information System (OASIS), further emphasize the commercial elements of these subjects, and that this information, shared with other market participants, may easily be subject to FERC transparency rules commonly known as FERC Standards of Conduct under Rule 888. The definition of AFC also explicitly contains the term, "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." This seems to leave little question about the market focus of particularly Flowgate Capability.

MOD-020-0, Requirement R1 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

MOD-031-2 and IRO-010-2 do not give the necessary entities the authority to request relevant information, nor does MOD-031-2 and IRO-010-2 require the associated entities to provide that information. Demand-Side Management (DSM) data may be related to the near-term operating time horizon and/or the planning time horizons, but not to the Real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4, Requirements R1 and R2, and IRO-001-4, Requirement R1, the RC, BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over DSM. They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4, Requirement R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0, Requirement R1, are sources of DADS data, have access to DADS data, or both.

DSM and Direct Control Load Management (DLCM) may be regarded as long-term planning and operations planning time horizon resources, but particularly with a "on request within 30 calendar days" obligation in the requirement, is not a resource for the Real-time or day-ahead operating time horizon for RCs and TOPs, which must plan to operate, and actually operate, the BES within SOL's and IROL's, a subset of SOLs. In addition, the amount of interruptible demands and DLCM at the TP, Resource Planner (RP), and/or LSE (which has been removed from the compliance registry and is no longer obligated to comply with NERC standards) level is not of locational benefit to TOPs and RCs to assist them in operating within SOL's, as such information, were it to be provided within a usable time frame, would not be sufficiently granular to assist the TOP and RC. All meaningful information regarding interruptible demands and DLCM is available from DADS, which in the United States (US), is a mandatory reporting mechanism, regulated per Section 1600 of the NERC Rules of Procedure. DSM and DLCM are financially-enabled mechanisms whereupon RPs may encourage customers and customer groups to permit local control of their load in exchange for rate considerations, and this local control may or may not be sited in such a manner to provide any benefit to TOP's and RC's; which, again, are obligated by NERC Standards to operate the BES within SOL's.

PRC-004-5(i), Requirement R4
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this requirement should be retired for the following reasons:

The standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for BES Elements. The Reliability Standard's Guideline and Technical Basis for Requirement R4 considers due diligence that an entity must make in determining the cause of a Protection System Misoperation.

The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with Requirements R1 and R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a Misoperation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation, and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of Requirement R4 does not preclude the entity's responsibility to continue the investigation to identify the cause of Misoperations; however, it does alleviate the need to keep tracking documents for showing investigative actions.

PRC-015-1 Requirements R1, R2, and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this standard should be retained for the following reasons:

PRC-015-1 is scheduled to be retired on 12/31/2020 under the PRC-012-2 Implementation Plan (IP).

PRC-018-1 Requirements R1, R2, R3, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this standard should be retained for the following reasons:

PRC-018-1 is superseded by PRC-002-2 in Year 2022. The PRC-002-2 IP states: "Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2…"

TOP-001-4 Requirements R16, R17, R19 and R22
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain Requirements R16 and R17, Retire Requirements R19 and R22
Rationale
The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator (SO) has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17, were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17, is not being sought during this phase of the project.

The purpose of TOP-003-3 is to ensure adequate data is collected by the BA and TOP to fulfill their operational and planning responsibilities. The purpose of TOP-002-4 is to ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22, for the BA and TOP are redundant with TOP-003-3, Requirements R3, R4 and R5, and TOP-002-4, Requirement R1.

The SDT determined Requirements R19 and R22 should be retired for the following reasons:

TOP-001-4, Requirement R19, is redundant to other requirements in the Transmission Operations (TOP) family of standards. For TOPs, the existing TOP-003-3, Requirement R5, cannot be fulfilled by entities unless data exchange capabilities exist between the TOP and the supplying entities. Similarly, TOP-002-4, Requirement R1, cannot be fulfilled by the TOP unless the data needed to perform the OPA has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R19 in TOP-001-4 is not needed to support reliability and can be retired.

TOP-001-4, Requirement R22, is redundant to other requirements in the TOP family of standards. For the

BA, the existing TOP-003-3, Requirement R5, cannot be fulfilled by entities unless data exchange capabilities exist between the BA and the supplying entities. Similarly, TOP-002-4, Requirement R4 cannot be fulfilled by the BA unless the data needed to develop its Operating Plan for next-day operations has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R22 in TOP-001-4 is not needed to support reliability and can be retired.

VAR-001-5*, Requirements R2 and R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R2, Retain Requirement R3
Rationale
The SDT determined Requirement R2 should be retired for the following reasons:

VAR-001-5, Requirement R2 states, "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load"

VAR-001-5, Requirement R2, contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately.

The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the OPA as described and required in TOP-002-4 and the criteria described in TOP-001-4, Requirement R10, the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis (RTCA) tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Additionally, the TOP uses Real-time monitoring, allowing it to make real-time decisions on voltage during normal conditions. These allow the TOP to quantify the use of reactive resources and makes VAR-001-5, Requirement R2, unnecessary.

Further to this requirement that a TOP have sufficient reactive resources, the planning standard TPL-001-4 requires the PA and TP to conduct studies on their transmission Systems to ensure it operates reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. These studies include available reactive resource capabilities. The studies provide corrective action plans (CAPs) when the analysis indicates an inability of the System to meet performance requirements. CAPs include, as necessary, the amount of reactive resource capabilities needed. This ensures that the TOP has available an adequate number of reactive resources to operate under normal contingency conditions.

TOP-002-4, Requirement R1, requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10, provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. The requirements in TOP-001-4 and TOP-002-4 direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-

5 requirements mandate that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The Facilities Design, Connections and Maintenance (FAC) family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and System ratings.

Specifically,

1. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement R1 of this standard requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOL's. Requirement R2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific System restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition; one such tool is reactive resources. The TOP must have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate or sufficient number is determined through analysis.

2. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement R13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes, and Requirement R14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

   This requirement, again, addresses that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of TOP exists here as it did under TOP-002-4; the TOP must have an adequate number of reactive resources to mitigate SOL exceedances. The adequate or sufficient number is determined through analysis.

The second sentence of VAR-001-5 R2 states: "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the VAR Enhanced Periodic Review group during its September 2016 meeting, and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then, as well as now, that perhaps this language be moved to a guidance section or document.

The SDT determined that Requirement R3 should be retained for the following reasons:
For reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL to prevent voltage-collapse events wherein the operation within SOLs/IROLs itself is not adequate to assure stable voltage operations in both steady-state and transient

conditions. The TOP family of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary.

* VAR-001-4.2 is an inactive standard. VAR-001-5 changed the Western Electricity Coordinating Council (WECC) variance, and not the continent-wide requirements. VAR-001-5 became effective January 1, 2019.

Exhibit F

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed revised and retired Reliability Standards developed through Project 2018-03 Standards Efficiency Review Retirements 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 ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2018-03 – Standards Efficiency Review SDT members is included in **Exhibit G**.

II. Standard Development History

A. Background

The purpose of Project 2018-03 – Standards Efficiency Review was to consider which standards could be revised or retired based on the review in phase one of the Standards Efficiency Review ("SER") initiative.[3]

The purpose of the SER was is to evaluate NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. In phase one of the SER, each existing and future enforceable Reliability Standard requirement addressing operations and planning (i.e., excluding CIP) was assigned to a review subteam for evaluation based on its associated time horizon (Real-time Operations, Long-

---

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

[2] NERC, *Standard Processes Manual* (2019), https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

[3] Details of phase one of the Standards Efficiency Review initiative can be found here: https://www.nerc.com/pa/Stand/Pages/Standards-Efficiency-Review.aspx.

term Planning, and Operations Planning). Each SER subteam was composed of individuals that, combined, represented a broad range of experience; including compliance, engineering, operations, planning, and legal. The cross-functional expertise of the subteams allowed for a more comprehensive review from multiple viewpoints. Along with the subteam reviews, NERC asked stakeholders to submit an SER Matrix spreadsheet indicating potential revisions and retirements among existing Reliability Standards. SER Matrix submissions were open from December 13, 2017 through February 2, 2018.

Based on the SER Matrix responses and the results of subteam reviews, the review team developed a draft SAR recommending retiring over 100 requirements across more than 30 standards. The SER review team posted its recommendations in the form of a draft SAR for comments from June 7, 2018 through July 10, 2018. The SER review team submitted a SAR to NERC on August 7, 2018.

B. Standard Authorization Request Development

On August 22, 2018, the NERC Standards Committee authorized the posting of the SER SAR and the solicitation of nominations for a Project 2018-03 Standards Efficiency Review drafting team. The SAR was posted for a 30-day formal comment period from August 28, 2018 through September 26, 2018. On October 17, 2018, the Standards Committee appointed a standard drafting team.

C. First Posting – Comment Period, Initial Ballot, and Non-binding Poll

The Project 2018-03 – Standards Efficiency Review drafting team considered each of the retirement recommendations contained in the SAR and determined that it was appropriate to pursue retirements in the standards listed below as well as those in the FAC, INT, MOD, and

PRC families addressed in a separate concurrently-filed petition.[4] Where the team determined to propose the retirement of one or more individual requirement(s) in Reliability Standards, the team proposed a new version of the standard in which the retired requirement(s) was replaced with the word "Reserved."

The following proposed revised Reliability Standards, the associated Implementation Plan, Violation Risk Factors, Violation Severity Levels, and other associated documents were posted for a 45-day formal comment period from February 27, 2019 through April 12, 2019 with a parallel initial ballot and non-binding poll held during the last 10 days of the comment period from April 3, 2019 through April 12, 2019. The results are summarized in the table below. The voting statistics are listed below, and the Ballot Results page provides detailed results.[5]

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
IRO-002-6 (revise)[6]	87.58% / 98.53%	84.23% / 99.47%
TOP-001-5 (revise)	85.67% / 98.96%	83.39% / 97.66%
VAR-001-6 (revise)	86.39% / 97.69%	83.73% / 95.77%

D. Final Ballot

The proposed Reliability Standards were posted for a 10-day final ballot period from April 23, 2019 through May 2, 2019. The voting statistics are listed below, and the Ballot Results page provides detailed results.[7]

Standard	Quorum / Approval
IRO-002-7	90.60% / 97.19%
TOP-001-5	90.03% / 97.75%
VAR-001-6	89.56% / 96.57%

---

4 *Petition of NERC for Approval of Revised and Retired Reliability Standards under the NERC Standards Efficiency Review* (filed June 7, 2019) (docket pending).

5 https://sbs.nerc.net/Ballot/BallotResults.

6 On final ballot, this was assigned version number IRO-002-7.

7 https://sbs.nerc.net/Ballot/BallotResults.

E. Board of Trustees Adoption

The NERC Board of Trustees adopted the proposed Reliability Standards on May 9, 2019.[8]

---

8 NERC, *Board of Trustees Agenda Package* 37-39 (Agenda Item 5b: Standards Efficiency Review Retirements), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_May_9_2019_Agenda_Package.pdf.

Complete Record of Development

Project 2018-03 Standards Efficiency Review Retirements

Related Files

Status

The 10-day final ballots for the **Project 2018-03 Standards Efficiency Review Retirements** concluded **8 p.m. Eastern, Thursday, May 2, 2019** and 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.

Note: Proposed Reliability Standard IRO-002-7 reflects a change of version (during initial posting under this project it was posted as IRO-002-6) due to the addition of a new Variance for the WECC region, developed through the WECC standard development process and was adopted by the WECC Board of Directors on March 6, 2019. Proposed Reliability Standard VAR-001-6 reflects the version update from VAR-001-4.2 (an inactive standard). VAR-001-5 became effective January 1, 2019 due to the WECC variance.

Project Scope

The Standard Authorization Request (SAR) drafting team evaluated NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard Requirements. Many Reliability Standards have been mandatory and enforceable for 10+ years in North America. The SAR drafting team identified potential candidate requirements that are not essential for reliability, could be simplified or consolidated, and could thereby reduce regulatory obligations and/or compliance burden.

Each existing and future enforceable Reliability Standard Requirement was assigned to a Standards Efficiency Review (SER) SAR subteam for evaluation based on its associated time horizon. Each SER SAR subteam was composed of individuals that, combined, represented a broad range of experience; including compliance, engineering, operations, planning, and legal. The cross-functional expertise of the subteams allowed for a more comprehensive reviews from multiple viewpoints.

Standards Efficiency Review Page

Standards Efficiency Review Retirements (SER-Retirements)

In Phase 1 of the SER project, the SER-Retirements standards drafting team will implement the recommendations in the SAR. The SER-Retirements standards drafting team is comprised of a mix of team members with Real-time Operations, Long-term Planning, and Operations Planning expertise to evaluate each requirement in the body of NERC Reliability Standards for unconditional retirement; i.e., these requirements may be retired without any modifications to other standards or requirements. The observations/rationales for retiring the requirements are currently listed in the project's SAR.

Draft	Actions	Dates	Results	Consideration of Comments
Final Posting **Proposed Partial Retirements** FAC-008-4 Clean **(73)** | Redline to Last Approved **(74)** INT-006-5 Clean **(75)** | Redline to Last Approved **(76)** INT-009-3 Clean **(77)** | Redline to Last Posted **(78)** | Redline to Last Approved **(79)** IRO-002-7 Clean **(80)** | Redline to Last Posted **(81)** | Redline to Last Approved **(82)** (IRO-002-5) PRC-004-6 Clean **(83)** | Redline to Last Posted **(84)** | Redline to Last Approved **(85)** TOP-001-5 Clean **(86)** | Redline to Last Approved **(87)** VAR-001-6 Clean **(88)** | Redline to Last Approved **(89)** **Proposed Complete Retirements** FAC-013-2 **(90)** INT-004-3.1 **(91)** INT-010-2.1 **(92)** MOD-001-1a **(93)** MOD-004-1 **(94)** MOD-008-1 **(95)** MOD-020-0 **(96)** MOD-028-2 **(97)** MOD-029-2a **(98)** MOD-030-3 **(99)** **Proposed Withdrawal** MOD-001-2 **(100)**	Final Ballots Info **(119)** Vote	04/23/2019 - 05/02/19	**Ballot Results** FAC-008-4 **(120)** FAC-013-2 **(121)** INT-004-3.1 **(122)** INT-006-5 **(123)** INT-009-3 **(124)** INT-010-2.1 **(125)** IRO-002-6 **(126)** MOD-001-1a **(127)** MOD-001-2 **(128)** MOD-004-1 **(129)** MOD-008-1 **(130)** MOD-020-0 **(131)** MOD-028-2 **(132)** MOD-029-2a **(133)** MOD-030-3 **(134)** PRC-004-6 **(135)** TOP-001-5 **(136)** VAR-001-6 **(137)**	

Implementation Plan Clean **(101)** | Redline to Last Posted **(102)** **Supporting Materials** VRF/VSL Justifications FAC-008-4 Clean **(103)** | Redline to Last Posted **(104)** INT-006-5 Clean **(105)** | Redline to Last Posted **(106)** INT-009-3 Clean **(107)** | Redline to Last Posted **(108)** IRO-002-7 Clean **(109)** | Redline to Last Posted **(110)** PRC-004-6 Clean **(111)** | Redline to Last Posted **(112)** TOP-001-5 Clean **(113)** | Redline to Last Posted **(114)** VAR-001-6 Clean **(115)** | Redline to Last Posted **(116)** Technical Rationale Clean **(117)** | Redline to Last Posted **(118)**				
Initial Posting **Proposed Partial Retirements** FAC-008-4 Clean **(8)** | Redline **(9)** INT-006-5 Clean **(10)** | Redline **(11)** INT-009-3 Clean **(12)** | Redline **(13)** IRO-002-6 Clean **(14)** | Redline **(15)** PRC-004-6 Clean **(16)** | Redline **(17)** TOP-001-5 Clean **(18)** | Redline **(19)** VAR-001-6 Clean **(20)** | Redline **(21)** **Proposed Complete Retirements** FAC-013-2 **(22)** INT-004-3.1 **(23)** INT-010-2.1 **(24)** MOD-001-1a **(25)** MOD-004-1 **(26)** MOD-008-1 **(27)** MOD-020-0 **(28)** MOD-028-2 **(29)** MOD-029-2a **(30)** MOD-030-3 **(31)** **Proposed Withdrawal** MOD-001-2 **(32)**	Initial Ballots and Non-binding Polls Updated Info **(45)** Info **(44)** Vote	04/03/19 - 04/12/2019	**Ballot Results** FAC-008-4 **(46)** FAC-013-2 **(47)** INT-004-3.1 **(48)** INT-006-5 **(49)** INT-009-3 **(50)** INT-010-2.1 **(51)** IRO-002-6 **(52)** MOD-001-1a **(53)** MOD-001-2 **(54)** MOD-004-1 **(55)** MOD-008-1 **(56)** MOD-020-0 **(57)** MOD-028-2 **(58)** MOD-029-2a **(59)** MOD-030-3 **(60)** PRC-004-6 **(61)** TOP-001-5 **(62)** VAR-001-6 **(63)** **Non-binding Poll Results** FAC-008-4 **(64)** INT-006-5 **(65)**	

Implementation Plan **(33)** **Supporting Materials** Unofficial Comment Form (Word) **(34)** VRF/VSL Justifications FAC-008-4 **(35)** INT-006-5 **(36)** INT-009-3 **(37)** IRO-002-6 **(38)** PRC-004-6 **(39)** TOP-001-5 **(40)** VAR-001-6 **(41)** Technical Rationale **(42)**			INT-009-3 **(66)** IRO-002-6 **(67)** PRC-004-6 **(68)** TOP-001-5 **(69)** VAR-001-6 **(70)**	
	Comment Period Info **(43)** Submit Comments	02/27/19 - 04/12/19	Comments Received **(71)**	Consideration of Comments **(72)**
	Join Ballot Pools (Each standard is being balloted separately. Therefore, multiple ballot pools must be joined in order to vote on all of the standards)	02/27/19 - 03/28/19		
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(6)**	Nomination Period Info **(7)** Submit Nominations	08/28/18 - 09/17/18		
Standard Authorization Request **(1)** **Supporting Materials** Unofficial Comment Form (Word) **(2)**	Comment Period Info **(3)** Submit Comments	08/28/18 - 09/26/18	Comments Received **(4)**	Consideration of Comments **(5)**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Efficiency Review (SER) Recommendations for Retirement-Draft		
Date Submitted:	August 7, 2018		
SAR Requester			
Name:	Standards Efficiency Review (SER) Team (Charles Rogers, Michael Cruz-Montes, Latroy Brumfield)		
Organization:	Standards Efficiency Review (SER) Team		
Telephone:		Email:	
SAR Type (Check as many as apply)			
☐ New Standard ☐ Revision to Existing Standard(s) ☐ Add, Modify or Retire a Glossary Term ☒ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Many NERC Reliability Standards have been mandatory and enforceable for over 10 years in North America, Phase 1 of the Standards Efficiency Review (SER) project seeks to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Phase 1 of this project reduces the number of mandatory and enforceable requirements with which registered entities must comply.			

Project Scope (Define the parameters of the proposed project):
The Standards Efficiency Review (SER) team used a risk-based approach to evaluate the reliability benefit of each requirement. Based on its analyses, the SER team is recommending the requirements listed below be retired. • BAL-005-1 R4, R6 • COM-002-4 R2 • EOP-005-3 R8 • EOP-006-3 R7 • FAC-008-3 R7, R8 • FAC-013-2 R1, R2, R4, R5, R6 (All) • INT-004-3.1 R1, R2, R3 (All) • INT-006-4 R3.1, R4, R5 • INT-009-2.1 R2 • INT-010-2.1 R1, R2, R3 (All) • IRO-002-5 R1, R4, R6 • IRO-008-2 R6 • IRO-014-3 R3 • IRO-017-1 R3 • MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All) • MOD-001-2 R1, R2, R3, R4, R5, R6 (All) • MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All) • MOD-008-1 R1, R2, R3, R4, R5 (All) • MOD-020-0 R1 (All) • MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All) • MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All) • MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All) • PRC-004-5(i) R4 • PRC-015-1 R1, R2, R3 (All) • PRC-018-1 R1, R2, R3, R4, R5, R6 (All) • TOP-001-4 R16, R17, R19, R22

- VAR-001-4.2 R2, R3
- VAR-001-4.2 E.A.15

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):

In Phase 1 of the Standards Efficiency Review (SER) project, three SER teams [Real-time Operations (RT), Long-term Planning (LT), and Operations Planning (OP)] evaluated each requirement in the body of NERC Reliability Standards for unconditional retirement i.e. these requirements may be retired without any modifications to other standards or requirements. The observations/rationales for retiring the requirements (identified in the Project Scope above) are listed below.

BAL-005-1 R4, R6 (RT)
The reliability objective of this requirement is duplicative of TOP-010-1(i) R2.

The Balancing Authority is already required by TOP-010-1(i) R2 to have an Operating Process/Procedure to address quality of Real-time data (including Reporting ACE) which includes criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities.

The same logic applies for R6 since TOP-010-1(i) R2 requires an Operating Process/Procedure to include criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities.

COM-002-4 R2 (RT)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. Issuing and receiving Operating Instructions according to a company's specific communications protocols is a fundamental Real-time reliability-related task and would be included in an entity's PER-005-2 training program to ensure System Operators are competent to perform the activities necessary for compliance with COM-002-4 R4 – R7. Additionally, Communication Methods (e.g. Three-Part Communications) is part of the knowledge content expected to be performed by all System Operators for the Certififcation Examination.

EOP-005-3 R8 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

EOP-006-3 R7 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

FAC-008-3 R7, R8 (OP)
These requirements are duplicative of the data provision standards MOD-32-1, IRO-010-2, and TOP-003-3.

In MOD-032-1 R1, the PC and TP develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the TO and GO provide power capabilities data in item 3 and facility ratings data in items 3f, 4c, 6g in the steady-state column of Attachment 1 as requested by the TP or PC.

IRO-010-2 R1 and TOP-003-3 R1 require the RC and TOP to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2 R3 and TOP-003-3 R5 require the TO and GO to respond to the RC's and TOP's requests.

FAC-013-2 R1, R2, R4, R5, R6 (ALL) (LT)
The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities.
In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as Transmission Planners (TP), do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable system performance is.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.
- R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.

- Assessing transfer capability above the “known commitments for Firm Transmission Service and Interchange” required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness.

Additionally, the proposed retirement of FAC-013 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project identified R2 and R3 as administrative and recommended them for retirement. R3 was approved for retirement by FERC in 2014.

INT-004-3.1 R1. (RT and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered function. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of the NAESB WEQ Business Practice Standards, specifically covered in existing NAESB WEQ-004-1 and WEQ-004-5, and in proposed NAESB WEQ-004-1.8. Additionally, the NERC Independent Expert Review Panel concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R2 (RT and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered entity. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of a currently proposed revision to the NAESB WEQ Business Practice Standards. The language in R2, requiring Confirmed Interchange associated with Dynamic Schedules or Pseudo-Ties being updated for future hours when any of the three conditions cited in the requirement occur, is contained almost verbatim in the proposed NAESB WEQ-004-23. Additionally, the Independent Expert Review Team concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R3 (OP)
This requirement qualifies for Paragraph 81 retirement as it only obligates entities to register information with an entity, which the failure to do so would create no discernable reliability impact. The standard states the purpose of the requirement is allow for pseudo-tie coordination, which is already guided and more clearly explained within the NERC Pseudo-Tie Coordination Reference Document. Reliability Coordinator visibility to Pseudo-Ties is provided under existing NERC Standard IRO-010-2 Requirement R2. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-006-4 R3.1 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this

requirement. The INT PRT found no impact on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. Additionally, RCs are notified via the electronic tag when a Reliability Adjustment Arranged Interchange is denied, as required in the NAESB e-Tagging Specifications.

INT-006-4 R4 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.3.1 and Section 1.3, and is not a reliability-related task performed by a NERC registered entity.

INT-006-4 R5 (RT)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.4, and is not a reliability-related task performed by a NERC registered entity. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-009-2.1 R2 (RT)
This requirement can be retired under Paragraph 81 Criteria B7, as the requirement for Balancing Authorities to establish an agreed upon interchange metering source is redundant with approved NERC Reliability Standard BAL-005-1, R7.

INT-010-2.1 R1, R3 (RT)
These requirements satisfy Paragraph 81 Criteria ‘B6 – Commercial or Business Practice’ and ‘B7 – Redundant’ because more stringent requirement(s) that meet the objectives are already included in WEQ-004-1 of the NAESB WEQ Business Practice Standards. In the absence of these requirements, all Interchange would have an RFI submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of an RFI after Interchange has begun is for commercial purposes rather than reliability issues. The requirement to submit an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1 R2 (RT)
This requirement satisfies Paragraph 81 Criteria ‘B6 – Commercial or Business Practice’ and ‘B7 – Redundant’ because more stringent tagging requirement(s) that meet the objectives are already included in WEQ-004-8 of the NAESB WEQ Business Practice Standards. In the absence of this requirement, all Reliability Adjustment Arranged Interchange would have a modification submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of a modification to a RFI after the modification has begun is for commercial purposes rather than reliability issues. The requirement to modify an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5 R1 (OP)

The requirement is a control for aiding compliance with IRO-008-2 R1 related to the performance of an Operational Planning Analysis (OPA), and it is duplicative to R3 in IRO-010-2. IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to fulfill IRO-010-2 R3, it must be able to exchange data with the requesting RC. Additionally, to comply with IRO-008-2 R1, the RC must have received all of the data it needs to perform the OPA. Finally, the measure (M1) for IRO-002-5 R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature.

IRO-002-5 R4 (OP)

This requirement can be retired because it does not contribute to reliability of the BES. The authority to approve or deny outages to any equipment, whether load-carrying or not, is a fundamental attribute of the System Operator role.

IRO-002-5 R6 (RT)

This requirement to have monitoring systems is unnecessary because IRO-002-5 R5 requires the monitoring of the systems which pre-supposes the ability (tools) to do so.

IRO-008-2 R6 (RT)

There is a potential for this requirement to become purely administrative in nature and not provide any reliability benefits. An Operating Plan required by IRO-014-3 R1, Part 1.1. or IRO-008-2 R5 would already include specific actions to notify impacted parties. The notifications for this requirement are after-the-fact and if the TOP, BA or other RC are a party to the implemented Operating Plan, then they would already be following the direction of the RC until notified.

IRO-014-3 R3 (RT)

The reliability objective of “notification” is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (R1, Part 1.1).

IRO-017-1 R3 (LT)

The reliability objective of this requirement is duplicative of the reliability objective of TPL-001-4, R8 which mandates each Planning Coordinator and Transmission Planner distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners and to any other functional entity that has a reliability related need and submits a written request.

MOD-020-0 R1 (ALL) (LT)

This requirement is duplicative of the data provision requirements included in Reliability Standards MOD-031-2 and IRO-010-2.

MOD-020-0 R1 requires the Load-Serving Entity, Transmission Planner, and Resource Planner to provide Interruptible Demand and Direct Control Load Management upon requests by the Transmission Operators, Balancing Authorities, and Reliability Coordinators.

In MOD-031-2 R1.4.5 requires the Planning Coordinator or Balancing Authority to request, as necessary, total available peak hour forecast of controllable and dispatchable Demand Side Management from the applicable entities. R2 then requires each applicable entity identified in the data request to provide the requested data to the PC or BA.

In IRO-010-2 R1 requires the Reliability Coordinator to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments, and R2 requires the RC to distribute its data specifications to all applicable entities. R3 then requires each applicable entity to respond to the request as specified.

PRC-004-5(i) R4 (OP)
The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with requirements R1 & R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a mis-operation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity’s internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of R4 does not preclude the entity’s responsibility to continue the investigation to identify the cause of mis-operation. However, it does alleviate the need to keep tracking documents for the sake of showing investigative actions.

PRC-015-1 R1, R2, R3 (All) (LT)
PRC-015-1 will be retired as it will be superseded by PRC-012-2. R1 requires the applicable entities to maintain a list of RAS which is an administrative requirement that does not contribute to the reliability of the BES. R2 references PRC-012-1 R1 which is not enforceable and will be superseded by PRC-012-2. Requirement R3 will be superseded by PRC-012-2. In support of the Independent Expert Review Panel's (IERP) justification to retire the standard: "P81 Administrative/Documentation", this is an administrative requirement. RE and NERC already have authority to request such information.

PRC-018-1 R1, R2, R3, R4, R5, R6 (All) (LT)
This standard requires both the TO or GO to ensure that DME's installed per PRC-002-1 and meet specific criteria. PRC-002-1 was never approved by FERC but PRC-018 was approved on the basis that each RRO would establish a DME program and that even if PRC-002-1 were not approved; PRC-018 could be enforced per the RRO program. Most RRO's have retired their programs which establish the scope of DME's for this standard. Furthermore, there are differences in the methodologies used by the RRO’s to establish scope of DME’s and what is mandated by requirement R1 of PRC-002-2. The lists of DME’s and where they are installed will differ from PRC-018-1 and PRC-002-2.

TOP-001-4 R16, R17 (OP)
These requirements can be retired because the authority to approve or deny outages of any equipment, whether load carrying or not, is a fundamental attribute of the system operator role. This was recognized by NERC and FERC in Project 2007-03 where the authority language in former Standard TOP-001-1 R1 was removed from the revised TOP standards approved by both NERC and FERC.

TOP-001-4 R19 (OP)
The requirement is a control for aiding compliance with TOP-002-4 R1 related to the performance of an Operational Planning Analysis (OPA) and it is duplicative to requirements R5 in TOP-003-3. Standard TOP-003-3 requires the TOP to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R3), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting TOP. Additionally, to comply with TOP-002-4 R1, the TOP must have received all of the data it needs to perform the OPA.

TOP-001-4 R22 (OP)
The requirement is a control for aiding compliance with TOP-002-4 R4 related to preparing Operating Plans and it is duplicative to requirement R5 in TOP-003-3. Standard TOP-003-3 requires the BA to identify the data it needs to perform its analysis functions (R2), which entities need to provide such data (R4), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting BA. Additionally, to comply with TOP-002-4 R4, the BA must have received all of the data it needs to perform its analysis functions.

VAR-001-4.2 R2 (OP)
This requirement is duplicative of other SOL requirements. R2 is related to maintaining the system within SOLs because a voltage limit is a form of SOL. TOP-002-4 already requires TOPs to identify where the potential SOL exceedances might occur for next-day operations and prepare a plan to mitigate these potential SOL exceedances, including notifying entities of their role in those plans (R3). When moving into real-time operations, the requirements of TOP-001-4 govern and the TOP continues to be obligated to operate within SOLs and direct the operation of the system to operate within SOLs or return to operation within SOLs (R12 and R14). R1 of TOP-001-4 requires the TOP to act and direct action to maintain reliability, including obtaining necessary reactive resources as described in VAR-001-4.2 R2.

VAR-001-4.2 R3 (OP)
This requirement is duplicative of TOP-001-4 requirements:

- TOP-001-4 R1, which states that the TOP "shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions." The requirement to "act" using all available actions, whether by "its own actions" or by the actions of others via "issuing

Operating Instructions" is the same as VAR-001-4.2 R3 to "operate or direct ... operation of devices to regulate ... voltage and reactive flow."

- The purpose of the actions taken under VAR-001-4.2, R3 is the same purpose accomplished by TOP-001-4 R1, R10, R12, R13 and R14 by acting to operate within limits (SOLs and IROLs) to maintain reliability of its transmission system.

VAR-001-4.2 E.A.15 (RT)
This is a Regional variance requirement applicable to WECC only. The continent-wide requirement VAR-002-4.1 R2.3 addresses the same reliability objective.

Additionally, the following Standards and Requirements were consolidated into MOD-001-2 in project 2012-05, which was filed for regulatory approval on February 10, 2014, and is still pending approval.

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (OP)
MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (OP)
MOD-008-1 R1, R2, R3, R4, R5 (OP)
MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (OP)
MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (OP)
MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (OP)

The February 10, 2014 petition notes that ATC/AFC are commercially-based values used to facilitate a market for unused transmission capacity in an open access environment and that the values do not directly control the operation of the BPS. It further acknowledges that TOPs are ultimately responsible for operating the grid in a reliable manner consistent with System Operating Limits, not ATC/AFC values. Nevertheless, the filing proposes MOD-001-2 for approval by FERC indicating ATC/AFC values have the potential to influence Real-time conditions on the Bulk-Power System and impact Real-time operations. Although, ATC/AFC values may have the potential to influence Real-Time conditions, there are a number of approved Reliability Standards that address potential impacts to Real-time operations and operation of the grid in a reliable manner consistent with System Operation Limits. This includes TOP Reliability Standard improvements that have been filed and approved since the MOD-001-2 filing in February 2014. NAESB may further address market issues associated with ATC/AFC, however these commercially-based values and market related issues should not be addressed through NERC Reliability standards.

Therefore, we recommend that NERC withdraw the February 10, 2014 petition related to MOD-001-2 and proceed with the retirement of the above listed MOD standards.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The team did not identify any known cost impacts.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):

No unique characteristics of the BES facilities that may be impacted by this proposal were identified by the SER team.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
All.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
SER Project Team(s)
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
None identified by the SER team.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

Market Interface Principles

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
Does the proposed standard development project 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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	None identified.

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Unofficial Comment Form

Standards Efficiency Review

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System to provide feedback on the **Standards Efficiency Review (SER) Standards Authorization Request**. Comments must be submitted by **8 p.m. Eastern, Wednesday, September 26, 2018.**

Additional information about this project is available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email) or at 404-446-9671.

Background

Many NERC Reliability Standards have been mandatory and enforceable for 10+ years in North America. Phase 1 of the SER project seeks to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden. Using a risk-based approach, three SER teams [Real-time Operations (RT), Long-term Planning (LT), and Operations Planning (OP)] evaluated the reliability benefit of each requirement in the body of NERC Reliability Standards. Based on the analyses, the SER teams are recommending the requirements listed in this posting be retired. The SER Team maintains that these requirements can be retired without impacting any other standards; i.e., no modifications to other requirements in other standards are necessary. Phase 2 of the SER Project will focus on modifying and/or consolidating requirements throughout the body of standards.

Questions

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree that NERC should proceed with this project?

   ☐ Yes

   ☐ No

   Comments:

Standards Announcement

Standards Efficiency Review

Formal Comment Period Open through September 26, 2018

Now Available

A formal comment period for the **Standards Efficiency Review (SER) Standard Authorization Request** is open through **8 p.m. Eastern, Wednesday, September 26, 2018**.

Purpose

Many NERC Reliability Standards have been mandatory and enforceable for over 10 years in North America. Phase 1 of the SER project seeks to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues using the SBS, 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).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day.***

Next Steps

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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:	Standards Efficiency Review | SAR 2nd Posting
Comment Period Start Date:	8/28/2018
Comment Period End Date:	9/26/2018
Associated Ballots:	

There were 36 sets of responses, including comments from approximately 140 different people from approximately 95 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

2. Do you agree that NERC should proceed with this project?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Florida Municipal Power Agency	Brandon McCormick	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Exelon	Chris Scanlon	1,3,5,6		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
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	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

				Seattle City Light Ballot Body	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	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
CMS Energy - Consumers Energy Company	Jeanne Kurzynowski	1,3,4,5	RF	Consumers Energy Company	Jeanne Kurzynowski	Consumers Energy Company	1,3,4,5	RF
					Jim Anderson	Consumers Energy Company	1	RF
					Karl Blaszkowski	Consumers Energy Company	3	RF
					Theresa Martinez	Consumers Energy Company	4	RF
					David Greyerbiehl	Consumers Energy Company	5	RF
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Southern Company - Southern	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC

Company Services, Inc.					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
PSEG	Sean Cavote	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service	3	RF

						Electric and Gas Co.		
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Associated Electric Cooperative, Inc.	Todd Bennett	1,3,5,6		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC

					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	No
Document Name	
Comment	
Consumers Energy's position is that PRC-004-5(i) R4 can be removed as long as comments are added to R5 to clarify that a "meaningful investigation must occur to determine the root cause". That statement can then be considered for the next SAR committee. If the statement can't be considered at the next SAR committee, then Consumers' position would be to go with leaving R4. Consumers Energy is in agreement with retirement of the other requirements recommended for retirement.	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS agrees with the vast majority of these recommended retirements, but APS disagrees that EOP-005-3 R8 is duplicative of activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. While system restoration is a reliability-related task that would be included in an entity's training program for its System Operators, it is a risk to assume that all Transmission Operators would provide System restoration training under its operations training program at the frequency and of the scope required under EOP-005-2, R8 (parts 8.1-8.5).	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	

Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) strongly disagrees with the proposed retirement of VAR-001-4.2 R2 because requiring each Transmission Operator to schedule, provide, and have evidence of scheduling sufficient reactive resources to regulate voltage levels under normal and Contingency conditions is necessary for the reliability of the BES. Reactive power resources are required to maintain voltage stability on the BES. Therefore, removing the requirement to ensure that each Transmission Operator schedules and provides sufficient reactive resources and has the documentation that sufficient reactive resources have been scheduled will be harmful to ensuring the reliability of the BES. Instead of retiring VAR-001-4.2 R2, there should be additional guidance (i.e. Implementation Guidance) to suggest how the transmission control center complies with R2.

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

MOD-001-2: Duke Energy objects to the drafting team's recommendation to retire MOD-001-2. FERC has not yet ruled on NAESB standards, and eliminating the responsibilities in MOD-001-2 would be in direct conflict with FERC Order 890 and would leave the industry with no consistency on calculation of ATC. Without a consistent method of calculating ATC throughout the industry this would potentially force a BA/TOP to inspect every Tag. This is avoided by having MOD-001-2 enforceable.

FAC-013-2: Duke Energy re-states its disagreement with the proposal regarding FAC-013-2. This standard was developed in response to FERC Directives in Orders 693 and 729. In the Orders, FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon (years one through five) and communicate the results. We disagree with the notion that FAC-013-2 has no bearing on reliability of the BES. In the FAC-013-2 — Planning Transfer Capability White Paper that was drafted during development of the standard, the standard's benefit to reliability is stated:

"Further, FAC-013-2 requires that a Planning Transfer Capability Methodology Document (PTCMD) be developed for the calculation of Planning Transfer Capabilities (PTC) beyond 13 months in the future to provide additional information for the Planning Coordinator to use in planning for BES reliability."

Another pertinent excerpt from the White Paper mentions how FAC-013-2 covers aspects of grid reliability not covered in the TPL standards:

"The TPL planning standards do not specify the need to document transfer capability calculation methods that may be used in the planning horizon. To cover that aspect of planning for BES reliability, the FAC-013-2 standard specifies that Planning Coordinators must perform PTC calculations as part of the planning process, that the method must be documented and shared with other entities as specified in the standard."

Lastly, see the quote from the White Paper below that further illustrates the necessity of FAC-013-2, and how it helps address past concerns from FERC.

"The application of FAC-013-2 will provide PTC values that are an indicator of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. It will result in meeting FERC's concerns regarding transfer capability in the planning horizon and provide important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES."

IRO-017 (R3): FERC mandated that RC's and TP's coordinate on the impact of known outages on TPL assessment results. It appears that the SDT believes that this can be retired because the TPL standard requires TP's to send their assessment results to adjacent PC's and TP"s and anyone else

who asks. The result of this retirement may mean that nothing gets to the RC unless they ask and even then it doesn't require the TP and RC to work together to resolve conflicts.	
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 Dominion

Answer	No
Document Name	

Comment

We agree with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R2

The SAR rationale is that it is redundant with NAESB business practices. However, NAESB rules are not applicable in Ontario. While NAESB is more stringent, during reliability curtailments, system operators require flexibility given to them by INT-010 to manage the e-tags.

IRO-002-5 R4

This requirement is needed for the system operator to manage the grid.

IRO-008-2 R6

Keeping impacted entities informed in a timely fashion is good operating practice.

TOP-001-4 R16

This requirement is needed for the system operator to manage the grid.

TOP-001-4 R17

This requirement is needed for the system operator to manage the grid.

In the rationale presented to retire COM-002-4 R2, the SER is assuming or expecting that initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric Systemis being covered in PER-005-2. PER-005-2 does not prescribe what training entities must include.

In the rationale presented to retire EOP-005-3 R8, the SER is assuming or expecting that System restoration is a reliability-related task and would be included in an entity's training program for its System Operators. PER-005-2 does not prescribe what training entities must include.

FAC-003-4 Requirements R5 and R6: These requirements should be retired because R5 and R6 are controls and good utility practices but do not enhance BES reliability over R1 and R2. R1 and R2 fulfil the purpose of the standard through measurable actions. Also, the NERC Rules of Procedure allow consideration for extenuating circumstances relative to R5.

FAC-008-3 Requirement R8: Requirements R.8.1.2 and R8. 2 are not duplicative of TOP-003-3 or IRO-010-2. FAC-008-3 Requirement R8.2 necessitates that TOs provide to their associated RCs, PCs, TPs, TOs and TOPs the Requirement R8.1.2 "identity of the most limiting equipment of the Facilities," Requirement R8.2.1 "identity of the existing next most limiting equipment of the Facilities," and Requirement R8.2.2 "Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1," whereas the TOP-003-3 or IRO-1010-2 standards do not appear to have this requirement.

IRO-010-2 Requirement R1 specifies the types of data that an RC collects from applicable entities, so that the RC may perform OPAs, RTM and RTAs. The OPA RTM and RTA definitions (in the NERC Glossary of Terms) each mention "Facility Ratings" as an input (into OPA's, RTM and RTA's). However, neither IRO-010-2, Requirement R1, nor the OPA, RTM and/or RTA definitions (in the NERC Glossary of Terms) contain the level of specificity in FAC-008-3 Requirement R8 (to "identity the most and the existing next most limiting equipment of the Facilities" and "the Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1"). Similarly, TOP-003-3 Requirement R5 requires identified entities to fulfill a data specification provided by a BA or TOP so that OPAs, RTM, and RTA's may be performed. As in the case of IRO-010-2 Requirement R1 and the OPA, RTM and RTA definitions, TOP-003-3 does not require identification of the most and the existing next most limiting equipment of the Facilities and the Thermal Rating for the next most limiting equipment identified in FAC-008-3 Requirement R8, Part 8.2.1."

NUC-001-3 R1: The requirement is administrative in nature, as Requirement R1 actions are inherent in Requirement R2 since each entity "shall have in effect" an agreement.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

IESO thanks the Standard Efficiency Review (SER) teams for all their hard work reviewing and analyzing the NERC Standards and requirements for possible retirements. The IESO agrees with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R2

The SAR rationale is that it is redundant with NAESB business practices. NAESB is not regulatory and, therefore, we are not measured by compliance to NAESB. Furthermore, we do not design our business practices around NAESB rules.

While NAESB is more stringent, during reliability curtailments, we need the flexibility given to us by INT-010. This standard allows us to take action to address a reliability need and manage the e-tags after the concern has been addressed – allowing us to manage the e-tags later. We still need this flexibility as the e-tag system does not feed our dispatch tool directly and we would not want to be the "hold up" for a reliability curtailment so we can line up e-tag with our dispatch tools.

IRO-002-5 R4

This is fundamental to how we manage the grid. In the absence of this standard the RC's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

IRO-008-2 R6

When and RC, TOP or BA becomes aware another RC is exceeding an SOL or an IROL that RC, TOP or BA may need to take mitigating actions to maintain reliability, therefore we disagree that with the SAR rationale that this requirement is administrative in nature and does provide reliability benefit. Keeping impacted entities informed in a timely fashion is good operating practice.

TOP-001-4 R16

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

TOP-001-4 R17

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knoweledge to the system operator.

Likes 0	
Dislikes 0	

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer	No
Document Name	

Comment

PSEG generally agrees with the purpose, scope, and content of the SAR, with the following exceptions:

FAC-003-4 Requirements R5 and R6: These requirements should be retired because R5 and R6 are controls and good utility practices but do not enhance BES reliability over R1 and R2. R1 and R2 fulfil the purpose of the standard through measurable actions. Also, the NERC Rules of Procedure allow consideration for extenuating circumstances relative to R5.

FAC-008-3 Requirement R8: Requirements R.8.1.2 and R8. 2 are not duplicative of TOP-003-3 or IRO-010-2. FAC-008-3 Requirement R8.2 necessitates that TOs provide to their associated RCs, PCs, TPs, TOs and TOPs the Requirement R8.1.2 “identity of the most limiting equipment of the Facilities,” Requirement R8.2.1 “identity of the existing next most limiting equipment of the Facilities,” and Requirement R8.2.2 “Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1,” whereas the TOP-003-3 or IRO-1010-2 standards do not appear to have this requirement.

IRO-010-2 Requirement R1 specifies the types of data that an RC collects from applicable entities, so that the RC may perform OPAs, RTM and RTAs. The OPA RTM and RTA definitions (in the NERC Glossary of Terms) each mention “Facility Ratings” as an input (into OPA’s, RTM and RTA’s). However, neither IRO-010-2, Requirement R1, nor the OPA, RTM and/or RTA definitions (in the NERC Glossary of Terms) contain the level of specificity in FAC-008-3 Requirement R8 (to “identity the most and the existing next most limiting equipment of the Facilities” and “the Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1”). Similarly, TOP-003-3 Requirement R5 requires identified entities to fulfill a data specification provided by a BA or TOP so that OPAs, RTM, and RTA’s may be performed. As in the case of IRO-010-2 Requirement R1 and the

OPA, RTM and RTA definitions, TOP-003-3 does not require identification of the most and the existing next most limiting equipment of the Facilities and the Thermal Rating for the next most limiting equipment identified in FAC-008-3 Requirement R8, Part 8.2.1.”

NUC-001-3 R1: The requirement is administrative in nature, as Requirement R1 actions are inherent in Requirement R2 since each entity “shall have in effect” an agreement.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

In general Southern Company agrees with the proposed requirements for retirement. However, Southern Company disagrees with the recommendations and rationales to retire the proposed requirements as noted below:

Southern does not agree with the recommendation and rationale to retire BAL-005-1 R4 and R6. We believe that it is in the best interest of both clarity and reliability to have these requirements in both the BA and TOP standards as these functions are separately registered.

Southern does not agree that NERC should withdraw the petition regarding MOD-001-2. The combined effect of both MOD-001-2 and NAESB's WEQ-023 strike the appropriate balance between reliability and market related issues.

Southern Company recommends delaying the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 until NERC's MOD-001-2 and NAESB's WEQ-023 are approved by the Commission (FERC). Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Southern believes that reliability-related tasks are determined by each individual entity. There is no obligation in the current NERC Reliability Standards to include the topics covered in EOP-005-3 (R8) or EOP-006-3 (R7) in the reliability related tasks for a TOP.

Southern believes that reliability related tasks are determined by each individual entity. There is no obligation in a NERC standard requirement to include the topics covered in COM-002-4 R2 in the Reliability Related tasks for a TOP.

Southern does not agree with the rationale for retiring IRO-002-5 R4. While we agree with the statement in the rationale, it doesn’t cover how an Operator has authority over various entities to direct the cancellation of outages. It’s not found anywhere else in the NERC standards and for entities where the TOP may be a different company than the RC, an appropriately written NERC standard would help ensure that the RC Operator had the authority to deny a telecommunications outage that affected key operational data provided by the TOP to the RC.

Southern does not agree with the recommendation for IRO-014-3 R3. R1.1 does not require notification of RCs and leaves it to the discretion of the RC experiencing the emergency to determine who is notified. Moreover, what if the Emergency being experienced is not covered in an Operating Procedure, Process or Operating Plans? The rationale assumes that all Operating Plans are generic and would cover all possible Emergencies experienced, but R1 of the standard doesn’t state that.

Southern does not agree with the overall rationale for retiring TOP-001-4 R16 and R17. While we support the wording in the rationale, it doesn’t fully encapsulate how an Operator has authority over entities to direct the cancellation of outages. This language is not found anywhere else in the NERC Reliability Standards and for entities where the TO and GO may be a different company than the TOP, an appropriately written NERC standard would help ensure that the TOP Operator had the authority to deny a telecommunications outage that affected key operational data provided by the TO and/or GO to the TOP.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

We agree with all the requirements proposed for retirement and with their rationales, except for the following:

FAC-008-3 R7

We disagree with the rationale. As stated in the Hydro-Québec TransÉnergie's comments on the previous SAR, requirement FAC-008-3 R7 is not entirely redundant to MOD-032, IRO-010 and TOP-003 because the latter requirements to do address all the functions of FAC-008-3 R7.Namely, the TO function is excluded. The rationale should state that the TO function request is not essential to reliability and on that basis it is dropped and the remaining obligations are redundant to the aforementioned alternatives. If that is out of scope of this project, it should be addressed in the follow-on project. We consider that the requirement should be removed, one way or the other.

IRO-002-5 R6

We disagree with the stated rationale. As stated in the Hydro-Québec TransÉnergie's comments on the previous SAR, R6 requires communication over a “redundant infrastructure” which is not mentioned in requirement R5. Arguably, that aspect could be considered redundant to R2. In that case, the recommendation would remain valid.

COM-002-4 R2, EOP-005-3 R8, EOP-006-3 R7

The proposed transfer to PER-005-2 could leave a gap, as per our informal comments on the matter in the previous comment round.

IRO-006-5 R1

The applicable entity in requirement R1 is the RC. IRO-001-4 R2 is not applicable to the RC function. As such, we disagree with the rationale and the recommendation.

IRO-017-1 R3

We disagree on the stated rationale and with the recommendation. Removing R3 shifts the responsability for identifying the affected RC by a plan from the planner to the RC. Therefore, R3 is not duplicative with TPL-001-4 R8.

MOD-020-0 R1

We disagree with the rationale. MOD-020-1 allows operators (RC and TOP) to request information. In contrast, MOD-031-2 does not give RC or TOP the authority to request DSM information. IRO-010-2 does give the RC that authority but does not apply to the RP. So unless the NERC functional model guarantees that the DP has that information, there could be a gap.

PRC-004-5(i) R4

We disagree with the rationale and with the recommendation. If t is the case that auditors consider a non-compliance with respect to R2 or R3 a violation regardless of R4, then R4 is indeed useless. Since the intention of the standard was to allow an entity to extend its examination period, R2, R3 and R4 should be rewritten to achieve this intent. Cutting out R4 changes the intention of the standard to provide extensions to entities in order for them to identify causes of misops.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) agrees with the recommendations and rationales to retire the following requirements identified in the Standards Authorization Request (SAR):

FAC-008-3 R7, R8

FAC-013-2 R1, R2, R4, R5, R6 (All)

INT-004-3.1 R1, R2, R3 (All)

TOP-001-4 R19, R22

ERCOT does not oppose the retirement of the following requirements identified in the SAR, but does not necessarily agree with each stated rationale articulated in support of retirement:

BAL-005-1 R4, R6

COM-002-4 R2

EOP-005-3 R8

EOP-006-3 R7

INT-006-4 R3.1, R4, R5

INT-009-2.1 R2

INT-010-2.1 R1, R2, R3 (All)*

IRO-002-5 R1, R4, R6

IRO-008-2 R6

IRO-014-3 R3

IRO-017 R3

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All)

MOD-001-2 R1, R2, R3, R4, R5, R6 (All)

MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All)

MOD-008-1 R1, R2, R3, R4, R5 (All)

MOD-020-0 R1 (All)

MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All)

MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All)

MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All)

PRC-015-1 R1, R2, R3 (All)

PRC-018-1 R1, R2, R3, R4, R5, R6 (All)

TOP-001-4 R16, R17

VAR-001-4.2 R2, R3

VAR-001-4.2 E.A.15

*Because INT-009-2.1 R1 refers to INT-010-2, it may be preferable to defer consideration of the retirement of the requirements in INT-010-2 to Phase II of Standards Efficiency Review.

ERCOT does not agree with the recommendation and rationale to retire the following standard identified in the SAR for the reasons stated below:

PRC-004-5(i) R4

ERCOT does not support the outright retirement of PRC-004-5(i) Requirement R4 because to do so would eliminate the requirement to investigate in its entirety. However, ERCOT agrees that the requirement as written may impose unnecessary burden by requiring repeated investigations despite the potential inability of a Transmission Owner, Generator Owner, or Distribution Provider to identify the cause(s) of a Misoperation.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

A. BPA appreciates the opportunity to comment to the NERC Standards Effectiveness Review (SER) team on the path forward specifically concerning MOD-001-2 and the associated MOD standards (MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3.) BPA does not support the recommendation that NERC withdraw the February 10, 2014 petition to FERC related to MOD-001-2. Although NAESB completed the WEQ-023 Modeling Business Practice Standards which was based on a request from NERC to NAESB to address changes to the NERC MOD-001-2 Reliability Standards not yet ratified by FERC, FERC has not ratified the NAESB BPs. BPA supports the overall effort to migrate the commercial and business aspects of the NERC MOD Reliability Standards into corresponding NAESB Business Practice Standards, a position BPA filed on 09/26/16 in response to the FERC Notice of Proposed Rulemaking (156 FERC ¶ 61,055). In that NOPR, FERC makes clear that the status of the NAESB WEQ-023 Modeling standards and the NERC MOD-001-2 standards are now intertwined. Both are under consideration as part of FERC's overall inquiry into ATC calculations. This includes Docket No. RM14-7-000, dealing with the original February 10, 2014 petition, as well as a related inquiry into ATC from Docket No. AD15-5-000. BPA recommends FERC address the overall ATC topic currently pending these dockets. FERC guidance on the overall direction of ATC standards is overdue and essential before NERC and/or NAESB invest further resources into companion standards. Because only Regulated utilities fall under the purview of the NAESB business practices, BPA urges NERC to closely collaborate with NAESB so there is a joint recommendation moving forward to FERC if NERC intends to proceed with modifying its approach to the February 10, 2014 petition.

B. BPA disagrees with the retirement of INT-004-3.1. NAESB Business Practice Standard WEQ-004 version 3.1 and FERC Docket RM05-5-25 are pending FERC approval. Additionally, NAESB Business Practices are not enforceable. Finally, the Pseudo-Tie Coordination Reference Document is just that, a reference document, and also not enforceable.

C. BPA supports the retirement of all other requirments in scope.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI	
Answer	Yes
Document Name	
Comment	

AECI supports the comments provided by NRECA.

Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	
Comment	

Phase I calls for the full retirement of FAC-013-2, it is noted by the NSRF that the current NERC Project 2015-09 is proposing FAC-013-3. The NSRF asks whether FAC-013-3 needs to be referenced from the SAR for future handling, should the FAC-013 -2 retirement be successful.

Similar situation with VAR-001-4.2 E.A. 15. The NSRF notes that VAR-001-5, which has been approved by the NERC Board of Trustees, contains E.A. 15 in Attachment 1. Does VAR-001-5 E.A.15 need to be referenced from the SAR for future handling, should the VAR-001-4.2 E.A. 15 retirement be successful?

Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 6, Tay Sing
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5

Answer	Yes
Document Name	
Comment	

AEP supports the work and overall recommendations of the Standards Drafting Team with the following qualifiers:

AEP does not agree that PRC-004-5(i) R4 meets the drafting team's "Evaluation Criteria for Retiring Reliability Standards Requirements", as the declaration of "no cause found" is made only within this obligation (i.e. "is not redundant"). Regarding the reliability rationale, we would agree that not all investigative actions in and of themselves improve reliability, however the ability to track investigative actions over an extended period of time ensures more riguer is applied to the investigative progress.

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	
Comment	

On behalf of our City Light SMEs, there were no voiced concerns.

Likes 0	

Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

We agree with the following comments submitted by TAPS:

We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1

This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2

Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3

This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3

Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3

The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4

IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5

This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3

Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2

This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9

Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)

This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1

In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5

Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5

For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1

The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5

Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	
Response	
Patricia Boody - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
I support the comments submitted by TAPS and the FMPA.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC	
Answer	Yes
Document Name	
Comment	

JEA appreciates the effort of the SER Team and agrees with the recommendations and rationales to retire the proposed requirements with the exception of two comments:

1. JEA disagrees with the rationale for the retirement of PRC-004-5(i) R4. This requirement applies only when the cause of a Misoperation has not been determined and requires the TO/GO/DP to perform investigative actions every two quarters until a cause is identified OR a declaration is made that no cause was identified.

a) The SAR states, “Requirement R4 acts as a control to support compliance with requirements R1 & R3.” However, R4 is not a control for determining “whether its Protection System component(s) caused a Misoperation”, but is the next step if the cause of a Misoperation, “for a Misoperation identified in accordance with Requirement R1 or R3”, has not been determined.

b) The SAR also states, “It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a mis-operation”, but this is more than just in the best interest of the entity. R1 requires the entity to “identify whether its Protection System component(s) caused a Misoperation.”

c) The SAR also states, “However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause.” But, investigative actions do improve reliability if they result in the identification of a cause. If no cause is identified, the TO/GO/DP can simply declare that no cause was identified, thereby satisfying the requirement.

There may be valid reasons for retiring this requirement (milestone tracking doesn’t improve reliability, this is a typical best practice, etc.), but the reasons listed above are not valid based upon the current standard language.

2. JEA disagrees with the rationale for the retirements of COM-002-4 R2, EOP-005-3 R8, and EOP-006-3 R7. These requirements are not duplicated in the current version of PER-005-2. PER-005-2 R1.1 allows for the RC, BA, and TOP to create a list of BES “company-specific Real-time reliability-related tasks based on a defined and documented methodology”, but, if specific tasks are intended, then they should be stated directly. It’s implied that these reliability-related tasks would include communication protocols and system restoration, but PER-005-2 only requires a methodology to be followed rather than setting forth explicit minimum competency requirements which is what the requirements proposed for retirement include.

Furthermore, there is clear distinction between the “initial training” of COM-002-4 R2 which occurs “prior to that individual operator issuing an Operating Instruction” and the continuous learning of PER-005-2.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

COM-002-4 R2 –Requires initial training on communication protocols; NERC proposes that R2 be retired as this topic should be covered in a PER-005-2 compliant Systematic Approach to Training program. Training on ATC communication protocols and tasks to issue and receive op instructions are part of the SCO initial training program. As such, we agree with retirement of COM-002-4 R2.

EOP-005-3 R8 – requires annual system restoration training; NERC proposes that R8 be retired as this topic should be covered in a PER-005-2 compliant Systematic Approach to Training program. Agree as we have three tasks in regards to PSR in the SCO initial training program. Our continuing education program also has annual PSR training (classroom and DTS). As such, we agree with retirement of EOP-005-3 R8.

TOP-001-4 R16-NERC Certified Operators can be addressed through Certification Program and authority is part of the qualification. PER-005-2 training supports this. As such, we agree with retirement of TOP-001-4 R16.

TOP-001-4 R19: the language used to describe how this is managed is through requirements in TOP-003-3 and TOP-002-4. As such, we agree with retirement of TOP-001-4 R19.

VAR-001-4 R2: TOP-001 and TOP-002 require the Transmission Operator to identify System Operating Limit exceedances during real-time and next-day conditions, respectively. System Operating Limits include voltage limits and management of reactive resources as described in VAR-001-4 R2 is fulfilled by acting according to the TOP standards. As such, we agree with retirement of VAR-001-4 R2.

VAR-001-4 R3: The directive in VAR-001-4.2 R3 is fulfilled as a result of compliance with TOP-001-3 R1, R12 and R14; in that the obligation in R1 to maintain the reliability of its operator area is unachievable by the TO if it does not operate devices to regulate voltage and reactive flow; additionally, TOP-001 R 12 and R14 cover addressing System Operating Limits and Interconnection Reliability Operating Limits, where the definition includes voltage stability ratings and system voltage limits. As such, we agree with retirement of VAR-001-4 R3.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
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 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6, Group Name Exelon Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rebecca Baldwin - Transmission Access Policy Study Group - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree that NERC should proceed with this project?

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Definitely.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes NERC should proceed with this project in an effort to identify those current reliability standards that either are duplicative in nature or have little to no impact on improving reliability of the system.	
Likes 0	
Dislikes 0	
Response	

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG enthusiastically supports NERC for seeking to eliminate and modify standards requirements to improve their effectiveness and efficiency.	
Likes 0	
Dislikes 0	
Response	
Patricia Boody - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
I support the comments submitted by TAPS and the FMPA.	
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	
While we disagree with some of the recommendations of the SDT, we agree that the project has merit, and should proceed.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Yes

Document Name	
Comment	

FMPA agrees with the following comments submitted by TAPS:

We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1

This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2

Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3

This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3

Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3

The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4

IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5

This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3

Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2

This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9

Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)

This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1

In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5

Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5

For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1

The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5

Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

TAPS appreciates the work of the Standards Efficiency Review Teams in developing this SAR. We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)
Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3
R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4
R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7
There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3
Verify through NERC Certification program.

EOP-008-2 R2
Verify through NERC Certification program.

EOP-008-2 R3, R4
NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2
This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1
R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts
R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts
R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4
This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5
This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6
This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5
Inherent in R1.

FAC-003-4 R4
R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6
Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1
This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2
Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3
This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3
Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3
The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4
IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5
This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3
Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2
This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9
Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)
This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1
In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2
Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6
Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)
Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5
Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and

only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5
For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1
The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7
Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3
Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8
Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9
EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13
TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21
R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24
R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3
The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7
Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1
Administrative.

VAR-001-4.1 R1
Duplicative of FAC-014.

VAR-001-4.2 R5
All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3
Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4
Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5
Duplicative of other standards requiring data provision.

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	

Comment

On behalf of our City Light SMEs, we believe these requirements should be retired.

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer	Yes
Document Name	

Comment

Reclamation applauds this effort to retire duplicate and unnecessary requirements, and suggests a future project to consolidate additional requirements and evaluate the NERC Glossary of Terms for clarity and efficiency.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
there is value examining the standards/requirements after 10 years of being enforceable. Data requests may be enforced by NERC Rules of Procedure Section 1600. A company's compliance culture is known now along with their internal controls. It makes sense to alleviate administrative burdens by a comprehensive review approach. We applaud NERC for this important effort.	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Johnson - American Transmission Company, LLC - 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	

Joe McClung - JEA - 1,3,5 - FRCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1,3,5,6	
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 Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6, Group Name Exelon Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
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 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Comment Report

Project Name:	Standards Efficiency Review | SAR 2nd Posting
Comment Period Start Date:	8/28/2018
Comment Period End Date:	9/26/2018
Associated Ballots:	

There were 36 sets of responses, including comments from approximately 140 different people from approximately 95 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

2. Do you agree that NERC should proceed with this project?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Florida Municipal Power Agency	Brandon McCormick	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Exelon	Chris Scanlon	1,3,5,6		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
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	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

				Seattle City Light Ballot Body	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	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
CMS Energy - Consumers Energy Company	Jeanne Kurzynowski	1,3,4,5	RF	Consumers Energy Company	Jeanne Kurzynowski	Consumers Energy Company	1,3,4,5	RF
					Jim Anderson	Consumers Energy Company	1	RF
					Karl Blaszkowski	Consumers Energy Company	3	RF
					Theresa Martinez	Consumers Energy Company	4	RF
					David Greyerbiehl	Consumers Energy Company	5	RF
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Southern Company - Southern	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC

Company Services, Inc.					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
PSEG	Sean Cavote	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service	3	RF

						Electric and Gas Co.		
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Associated Electric Cooperative, Inc.	Todd Bennett	1,3,5,6		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC

					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company

Answer	No
Document Name	

Comment

Consumers Energy's position is that PRC-004-5(i) R4 can be removed as long as comments are added to R5 to clarify that a “meaningful investigation must occur to determine the root cause”. That statement can then be considered for the next SAR committee.

If the statement can’t be considered at the next SAR committee, then Consumers’ position would be to go with leaving R4.

Consumers Energy is in agreement with retirement of the other requirements recommended for retirement.

Likes 0	
Dislikes 0	

Response

Thank you for your comment and support. The additional requirements suggested are not identified within the SAR, and thus are out of scope for this project. Your comment will be referred to the Phase II Standards Efficiency Review Team for consideration in a future phase of their work.

Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

APS agrees with the vast majority of these recommended retirements, but APS disagrees that EOP-005-3 R8 is duplicative of activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. While system restoration is a reliability-related task that would be included in an entity's training program for its System Operators, it is a risk to assume that all Transmission Operators would provide System restoration training under its operations training program at the frequency and of the scope required under EOP-005-2, R8 (parts 8.1-8.5).

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The SER SDT agrees that Requirement R8 of EOP-005-3be retained. The SER SDT also believes that Requirement R7 of EOP-006-3 be maintained. The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training.

In PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

The SDT believes a specific requirement for system restoration training should be maintained because, while a system shutdown is low probability, it could have a high impact if not done properly.

The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training; and, if there is that opportunity, then Requirement R8 of EOP-005-3 may be able to be looked at for retirement within that project or in a future project. If certain elements are essential within an entity's training program, those elements should be explicitly identified in a future version of PER-005 prior to retiring from other standards; such as those identified in EOP-005.

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	

Comment

Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) strongly disagrees with the proposed retirement of VAR-001-4.2 R2 because requiring each Transmission Operator to schedule, provide, and have evidence of scheduling sufficient reactive resources to regulate voltage levels under normal and Contingency conditions is necessary for the reliability of the BES. Reactive power resources are required to maintain voltage stability on the BES. Therefore, removing the requirement to ensure that each Transmission Operator schedules and provides sufficient reactive resources and has the documentation that sufficient reactive resources have been scheduled will be harmful to ensuring the reliability of the BES. Instead of retiring VAR-001-4.2 R2, there should be additional guidance (i.e. Implementation Guidance) to suggest how the transmission control center complies with R2.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
VAR-001-5, Requirement R2 is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4 standards, which direct the TOP to plan and operate within in System Operating Limit (SOL) values, which includes system voltage limits. TOP-002-4, Requirement R1, requires the Transmission Operator to complete an Operational Planning Analysis (OPA) to assess whether any of its planned operations for the next day will exceed any System Operating Limits (SOL) ; TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. Requirements R1, R3, R4, R5 and R6 of VAR-001-5 ensure that a TOP require that voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. Finally, the FAC Standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

MOD-001-2: Duke Energy objects to the drafting team's recommendation to retire MOD-001-2. FERC has not yet ruled on NAESB standards, and eliminating the responsibilities in MOD-001-2 would be in direct conflict with FERC Order 890 and would leave the industry with no consistency on calculation of ATC. Without a consistent method of calculating ATC throughout the industry this would potentially force a BA/TOP to inspect every Tag. This is avoided by having MOD-001-2 enforceable.

FAC-013-2: Duke Energy re-states its disagreement with the proposal regarding FAC-013-2. This standard was developed in response to FERC Directives in Orders 693 and 729. In the Orders, FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon (years one through five) and communicate the results. We disagree with the notion that FAC-013-2 has no bearing on reliability of the BES. In the FAC-013-2 — Planning Transfer Capability White Paper that was drafted during development of the standard, the standard's benefit to reliability is stated:

"Further, FAC-013-2 requires that a Planning Transfer Capability Methodology Document (PTCMD) be developed for the calculation of Planning Transfer Capabilities (PTC) beyond 13 months in the future to provide additional information for the Planning Coordinator to use in planning for BES reliability."

Another pertinent excerpt from the White Paper mentions how FAC-013-2 covers aspects of grid reliability not covered in the TPL standards:

"The TPL planning standards do not specify the need to document transfer capability calculation methods that may be used in the planning horizon. To cover that aspect of planning for BES reliability, the FAC-013-2 standard specifies that Planning Coordinators must perform PTC calculations as part of the planning process, that the method must be documented and shared with other entities as specified in the standard."

Lastly, see the quote from the White Paper below that further illustrates the necessity of FAC-013-2, and how it helps address past concerns from FERC.

"The application of FAC-013-2 will provide PTC values that are an indicator of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. It will result in meeting FERC's concerns regarding transfer capability in the planning horizon and provide important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES."

IRO-017 (R3): FERC mandated that RC's and TP's coordinate on the impact of known outages on TPL assessment results. It appears that the SDT believes that this can be retired because the TPL standard requires TP's to send their assessment results to adjacent PC's and TP"s and anyone else who asks. The result of this retirement may mean that nothing gets to the RC unless they ask and even then it doesn't require the TP and RC to work together to resolve conflicts.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

IRO-017-1, Requirement R3: IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3 for retirement. The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TPL-001-4 to name the RC as a recipient; and, if there is that opportunity, then Requirement R3 of IRO-017-1 may be able to be looked at for retirement within that project or in a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and proposed MOD-001-2 – ATC/AFC, as well as tags (or eTags) are commercially-focused elements, facilitating interchange and balancing of interchange. The real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where they stated, "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 order, where they stated, "we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

FAC-013-2 - It is important to note the white paper referenced in the above comment was written in 2010. There have been significant substantive changes to the body of standards since that time. For example, referenced TPL and MOD standards have been superseded by newer versions, and other standards never became effective (FAC-012).

The white paper does not demonstrate continued need for the FAC-013-2 standard for the following reasons:

- As stated in the SER's justification for the retirement of FAC-013, "assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 Requirement R1.1.5 (2014), serves a market function as opposed to securing System reliability." It is true that some entities depend on power transfers to meet their load obligations, and assessing transfers would provide that entity a reliability benefit, but that is not true for all other entities.
- Also as stated in the SER's justification for the retirement of FAC-013, "R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability."
- The FAC-013 standard does not contain a requirement to develop or communicate "transfer capabilities" (values.
- There is no minimum performance requirement or minimum acceptable transfer capability or margin documented in the standard.

The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as Transmission Planners (TP), do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable system performance is.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.
- R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.
- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project identified R2 and R3 as administrative and recommended them for retirement. R3 was approved for retirement by FERC in 2014.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion

Answer	No
Document Name	

Comment

We agree with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R2

The SAR rationale is that it is redundant with NAESB business practices. However, NAESB rules are not applicable in Ontario. While NAESB is more stringent, during reliability curtailments, system operators require flexibility given to them by INT-010 to manage the e-tags.

IRO-002-5 R4

This requirement is needed for the system operator to manage the grid.

IRO-008-2 R6

Keeping impacted entities informed in a timely fashion is good operating practice.

TOP-001-4 R16

This requirement is needed for the system operator to manage the grid.

TOP-001-4 R17

This requirement is needed for the system operator to manage the grid.

In the rationale presented to retire COM-002-4 R2, the SER is assuming or expecting that initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric Systemis being covered in PER-005-2. PER-005-2 does not prescribe what training entities must include.

In the rationale presented to retire EOP-005-3 R8, the SER is assuming or expecting that System restoration is a reliability-related task and would be included in an entity's training program for its System Operators. PER-005-2 does not prescribe what training entities must include.

FAC-003-4 Requirements R5 and R6: These requirements should be retired because R5 and R6 are controls and good utility practices but do not enhance BES reliability over R1 and R2. R1 and R2 fulfil the purpose of the standard through measurable actions. Also, the NERC Rules of Procedure allow consideration for extenuating circumstances relative to R5.

FAC-008-3 Requirement R8: Requirements R.8.1.2 and R8. 2 are not duplicative of TOP-003-3 or IRO-010-2. FAC-008-3 Requirement R8.2 necessitates that TOs provide to their associated RCs, PCs, TPs, TOs and TOPs the Requirement R8.1.2 “identity of the most limiting equipment of the Facilities,” Requirement R8.2.1 “identity of the existing next most limiting equipment of the Facilities,” and Requirement R8.2.2 “Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1,” whereas the TOP-003-3 or IRO-1010-2 standards do not appear to have this requirement.

IRO-010-2 Requirement R1 specifies the types of data that an RC collects from applicable entities, so that the RC may perform OPAs, RTM and RTAs. The OPA RTM and RTA definitions (in the NERC Glossary of Terms) each mention “Facility Ratings” as an input (into OPA’s, RTM and RTA’s). However, neither IRO-010-2, Requirement R1, nor the OPA, RTM and/or RTA definitions (in the NERC Glossary of Terms) contain the level of specificity in FAC-008-3 Requirement R8 (to “identity the most and the existing next most limiting equipment of the Facilities” and “the Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1”). Similarly, TOP-003-3 Requirement R5 requires identified entities to fulfill a data specification provided by a BA or TOP so that OPAs, RTM, and RTA’s may be performed. As in the case of IRO-010-2 Requirement R1 and the OPA, RTM and RTA definitions, TOP-003-3 does not require identification of the most and the existing next most limiting equipment of the Facilities and the Thermal Rating for the next most limiting equipment identified in FAC-008-3 Requirement R8, Part 8.2.1.”

NUC-001-3 R1: The requirement is administrative in nature, as Requirement R1 actions are inherent in Requirement R2 since each entity “shall have in effect” an agreement.

Likes 0	
Dislikes 0	

Response

Thank you for your comments:

INT-009-2.1, Requirement R2: This requirement can be retired under Paragraph 81 criteria, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7. As discussed in the SAR, the SDT recommends retirement of INT-009-2.1, Requirement R2.

FAC-008-3/4, Requirement 8: This requirement is duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Provider (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

COM-002-4, Requirement R2: While the SDT agrees that training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to training on communications protocols; and, if there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or in a future project.

EOP-005-3, Requirement R8 and EOP-006-3 Requirement R7:

The SER SDT agrees that Requirement R8 of EOP-005-3be retained. The SER SDT also believes that Requirement R7 of EOP-006-3 be maintained. The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training.

In PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

The SDT team believes a specific requirement for system restoration training should be maintained, because while a system shutdown is low probability, it could have a high impact if not done properly The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training; and, if there is that opportunity, then Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 may be able to be looked at for retirement within that project or in a future project. If certain elements are essential within an entity's training program, those elements should be explicitly identified in a future version of PER-005 prior to retiring from other standards; such as those identified in EOP-005 and EOP-006.

NUC-001-3 R1: Is out of scope for this projects, as it is not listed in the final SAR. The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R1 of NUC-001-3 to determine if there is opportunity for revisions; and, if there is that opportunity, then Requirement R1 of NUC-001-3 may be able to be looked at for retirement within that project or in a future project.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

IESO thanks the Standard Efficiency Review (SER) teams for all their hard work reviewing and analyzing the NERC Standards and requirements for possible retirements. The IESO agrees with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R2

The SAR rationale is that it is redundant with NAESB business practices. NAESB is not regulatory and, therefore, we are not measured by compliance to NAESB. Furthermore, we do not design our business practices around NAESB rules.

While NAESB is more stringent, during reliability curtailments, we need the flexibility given to us by INT-010. This standard allows us to take action to address a reliability need and manage the e-tags after the concern has been addressed – allowing us to manage the e-tags later. We still need this flexibility as the e-tag system does not feed our dispatch tool directly and we would not want to be the "hold up" for a reliability curtailment so we can line up e-tag with our dispatch tools.

IRO-002-5 R4

This is fundamental to how we manage the grid. In the absence of this standard the RC's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

IRO-008-2 R6

When and RC, TOP or BA becomes aware another RC is exceeding an SOL or an IROL that RC, TOP or BA may need to take mitigating actions to maintain reliability, therefore we disagree that with the SAR rationale that this requirement is administrative in nature and does provide reliability benefit. Keeping impacted entities informed in a timely fashion is good operating practice.

TOP-001-4 R16

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

TOP-001-4 R17

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knoweledge to the system operator.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

INT-009-2.1, Requirement R2: This requirement can be retired under Paragraph 81 criteria, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7. As discussed in the SAR, the SDT recommends retirement of INT-009-2.1, Requirement R2.

TOP-001-4, Requirements R16 and R17 – The SDT agrees that these requirements are necessary for the real-time operators to be assured of having the tools necessary to monitor the BES and does not intend to seek retirement of these Requirements during this phase of the project.

IRO-002-5, Requirement R4 - The SDT agrees that these requirements are necessary for the real-time operators to be assured of having the tools necessary to monitor the BES and does not intend to seek retirement of this Requirement during this phase of the project.

IRO-008-2, Requirement R6 – Although IRO-008-2, Requirement R6 appears to be administrative in nature, the SDT believes there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, the team does not intend to seek retirement of this Requirement during this phase of the project.	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
PSEG generally agrees with the purpose, scope, and content of the SAR, with the following exceptions: **FAC-003-4 Requirements R5 and R6**: These requirements should be retired because R5 and R6 are controls and good utility practices but do not enhance BES reliability over R1 and R2. R1 and R2 fulfil the purpose of the standard through measurable actions. Also, the NERC Rules of Procedure allow consideration for extenuating circumstances relative to R5. **FAC-008-3 Requirement R8**: Requirements R.8.1.2 and R8. 2 are not duplicative of TOP-003-3 or IRO-010-2. FAC-008-3 Requirement R8.2 necessitates that TOs provide to their associated RCs, PCs, TPs, TOs and TOPs the Requirement R8.1.2 "identity of the most limiting equipment of the Facilities," Requirement R8.2.1 "identity of the existing next most limiting equipment of the Facilities," and Requirement R8.2.2 "Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1," whereas the TOP-003-3 or IRO-1010-2 standards do not appear to have this requirement. IRO-010-2 Requirement R1 specifies the types of data that an RC collects from applicable entities, so that the RC may perform OPAs, RTM and RTAs. The OPA RTM and RTA definitions (in the NERC Glossary of Terms) each mention "Facility Ratings" as an input (into OPA's, RTM and RTA's). However, neither IRO-010-2, Requirement R1, nor the OPA, RTM and/or RTA definitions (in the NERC Glossary of Terms) contain the level of specificity in FAC-008-3 Requirement R8 (to "identity the most and the existing next most limiting equipment of the Facilities" and "the Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1"). Similarly, TOP-003-3 Requirement R5 requires identified entities to fulfill a data specification provided by a BA or TOP so that OPAs, RTM, and RTA's may be performed. As in the case of IRO-010-2 Requirement R1 and the OPA, RTM and RTA definitions, TOP-003-3 does not require identification of the most and the existing next most limiting equipment of the Facilities and the Thermal Rating for the next most limiting equipment identified in FAC-008-3 Requirement R8, Part 8.2.1." **NUC-001-3 R1**: The requirement is administrative in nature, as Requirement R1 actions are inherent in Requirement R2 since each entity "shall have in effect" an agreement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **FAC-003-4 R5 and R6, and NUC-001-3** are not identified within the SAR, and thus are out of scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work. **FAC-008-3/4, Requirement 8:** This requirement is duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Provider (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.	

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

NUC-001-3 R1: Is out of scope for this projects, as it is not listed in the final SAR. The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R1 of NUC-001-3 to determine if there is opportunity for revisions; and, if there is that opportunity, then Requirement R1 of NUC-001-3 may be able to be looked at for retirement within that project or in a future project.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

In general Southern Company agrees with the proposed requirements for retirement. However, Southern Company disagrees with the recommendations and rationales to retire the proposed requirements as noted below:

Southern does not agree with the recommendation and rationale to retire BAL-005-1 R4 and R6. We believe that it is in the best interest of both clarity and reliability to have these requirements in both the BA and TOP standards as these functions are separately registered.

Southern does not agree that NERC should withdraw the petition regarding MOD-001-2. The combined effect of both MOD-001-2 and NAESB's WEQ-023 strike the appropriate balance between reliability and market related issues.

Southern Company recommends delaying the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 until NERC's MOD-001-2 and NAESB's WEQ-023 are approved by the Commission (FERC). Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Southern believes that reliability-related tasks are determined by each individual entity. There is no obligation in the current NERC Reliability Standards to include the topics covered in EOP-005-3 (R8) or EOP-006-3 (R7) in the reliability related tasks for a TOP.

Southern believes that reliability related tasks are determined by each individual entity. There is no obligation in a NERC standard requirement to include the topics covered in COM-002-4 R2 in the Reliability Related tasks for a TOP.

Southern does not agree with the rationale for retiring IRO-002-5 R4. While we agree with the statement in the rationale, it doesn't cover how an Operator has authority over various entities to direct the cancellation of outages. It's not found anywhere else in the NERC standards and for entities where the TOP may be a different company than the RC, an appropriately written NERC standard would help ensure that the RC Operator had the authority to deny a telecommunications outage that affected key operational data provided by the TOP to the RC.

Southern does not agree with the recommendation for IRO-014-3 R3. R1.1 does not require notification of RCs and leaves it to the discretion of the RC experiencing the emergency to determine who is notified. Moreover, what if the Emergency being experienced is not covered in an Operating Procedure, Process or Operating Plans? The rationale assumes that all Operating Plans are generic and would cover all possible Emergencies experienced, but R1 of the standard doesn't state that.

Southern does not agree with the overall rationale for retiring TOP-001-4 R16 and R17. While we support the wording in the rationale, it doesn't fully encapsulate how an Operator has authority over entities to direct the cancellation of outages. This language is not found anywhere else in the NERC Reliability Standards and for entities where the TO and GO may be a different company than the TOP, an appropriately written NERC standard would help ensure that the TOP Operator had the authority to deny a telecommunications outage that affected key operational data provided by the TO and/or GO to the TOP.

Likes 0	

Dislikes 0	

Response

Thank you for your comments.

The SER SDT agrees that Requirement R4 and R6 of **BAL-005-1** be retained, as both requirements are specific to the calculation of the ACE. The TOP-010-1(i) R2 covers ACE with the wording of "analysis functions and Real-time monitoring" but does not cover specifics such as quality flags for missing or invalid data that is part of the requirement for BAL-005-1 R4 or the accuracy of scan rates that is part of BAL-005-1 R6.

In TOP-010-1(i) R2 (revised from TOP-010-1) the requirement R2 covers the calculation and monitoring of ACE, while the language " Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring" this is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) the requirement R4 states "The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. Requirement R6 of BAL-005-1 states "Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each Balancing Authority Area. Both of these requirements are specific to identifying missing or invalid data plus scan rates not just the quality of the Real-time data.

The SER Phase I SDT will communicate the SR Phase II SAR DT regarding Requirement R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i) R2 that would satisfy the missing or invalid data plus scan rates and if there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be able to be looked at for retirement within the project or in a future project.

EOP-005-3, Requirement R8 and EOP-006-3 Requirement R7:

The SER SDT agrees that Requirement R8 of EOP-005-3be retained. The SER SDT also believes that Requirement R7 of EOP-006-3 be maintained. The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training.

In PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

The SDT team believes a specific requirement for system restoration training should be maintained, because while a system shutdown is low probability, it could have a high impact if not done properly The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training; and, if there is that opportunity, then Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 may be able to be looked at for retirement within that project or in a future project. If certain elements are essential within an entity's training program, those elements should be explicitly identified in a future version of PER-005 prior to retiring from other standards; such as those identified in EOP-005 and EOP-006.

COM-002-4 Requirement R2:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to training on communications protocols; and, if there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or in a future project.

IRO-014-3, Requirement R3: The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (R1, Part 1.1), this ensures RC operations are coordinated to maintain reliability of the

BES. As such a separate requirement for ensuring notifications are made to impacted RC's is duplicative. Requirement R1 would need to have a revised time horizon to Real-time horizon added to retire R3.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and proposed MOD-001-2 – ATC/AFC, as well as tags (or eTags) are commercially-focused elements, facilitating interchange and balancing of interchange. The real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where they stated, "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 order, where they stated, "we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

TOP-001-4, Requirements R16 and R17 – The SDT agrees that these requirements are necessary for the real-time operators to be assured of having the tools necessary to monitor the BES and does not intend to seek retirement of these Requirements during this phase of the project.

IRO-002-5, Requirement R4 - The SDT agrees that these requirements are necessary for the real-time operators to be assured of having the tools necessary to monitor the BES and does not intend to seek retirement of this Requirement during this phase of the project.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

We agree with all the requirements proposed for retirement and with their rationales, except for the following:

FAC-008-3 R7

We disagree with the rationale. As stated in the Hydro-Québec TransÉnergie's comments on the previous SAR, requirement FAC-008-3 R7 is not entirely redundant to MOD-032, IRO-010 and TOP-003 because the latter requirements to do address all the functions of FAC-008-3 R7.Namely, the TO function is excluded. The rationale should state that the TO function request is not essential to reliability and on that basis it is dropped and the remaining obligations are redundant to the aforementioned alternatives. If that is out of scope of this project, it should be addressed in the follow-on project. We consider that the requirement should be removed, one way or the other.

IRO-002-5 R6

We disagree with the stated rationale. As stated in the Hydro-Québec TransÉnergie's comments on the previous SAR, R6 requires communication over a "redundant infrastructure" which is not mentioned in requirement R5. Arguably, that aspect could be considered redundant to R2. In that case, the recommendation would remain valid.

COM-002-4 R2, EOP-005-3 R8, EOP-006-3 R7

The proposed transfer to PER-005-2 could leave a gap, as per our informal comments on the matter in the previous comment round.

IRO-006-5 R1

The applicable entity in requirement R1 is the RC. IRO-001-4 R2 is not applicable to the RC function. As such, we disagree with the rationale and the recommendation.

IRO-017-1 R3

We disagree on the stated rationale and with the recommendation. Removing R3 shifts the responsability for identifying the affected RC by a plan from the planner to the RC. Therefore, R3 is not duplicative with TPL-001-4 R8.

MOD-020-0 R1

We disagree with the rationale. MOD-020-1 allows operators (RC and TOP) to request information. In contrast, MOD-031-2 does not give RC or TOP the authority to request DSM information. IRO-010-2 does give the RC that authority but does not apply to the RP. So unless the NERC functional model guarantees that the DP has that information, there could be a gap.

PRC-004-5(i) R4

We disagree with the rationale and with the recommendation. If t is the case that auditors consider a non-compliance with respect to R2 or R3 a violation regardless of R4, then R4 is indeed useless. Since the intention of the standard was to allow an entity to extend its examination period, R2, R3 and R4 should be rewritten to achieve this intent. Cutting out R4 changes the intention of the standard to provide extensions to entities in order for them to identify causes of misops.

Likes 0	
Dislikes 0	

Response Thank you for your support.

Thank you for your comments:

FAC-008-3/4, Requirement 8: This requirement is duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3.

In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Provider (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

IRO-002-5, Requirement R4 - The SDT agrees that these requirements are necessary for the real-time operators to be assured of having the tools necessary to monitor the BES and does not intend to seek retirement of this Requirement during this phase of the project.

EOP-005-3, Requirement R8 and EOP-006-3 Requirement R7:

The SER SDT agrees that Requirement R8 of EOP-005-3be retained. The SER SDT also believes that Requirement R7 of EOP-006-3 be maintained. The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training.

In PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

The SDT team believes a specific requirement for system restoration training should be maintained, because while a system shutdown is low probability, it could have a high impact if not done properly The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training;

and, if there is that opportunity, then Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 may be able to be looked at for retirement within that project or in a future project. If certain elements are essential within an entity's training program, those elements should be explicitly identified in a future version of PER-005 prior to retiring from other standards; such as those identified in EOP-005 and EOP-006.

COM-002-4 Requirement R2:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to training on communications protocols; and, if there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or in a future project.

IRO-017-1, Requirement R3: IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3 for retirement. The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TPL-001-4 to name the RC as a recipient; and, if there is that opportunity, then Requirement R3 of IRO-017-1 may be able to be looked at for retirement within that project or in a future project.

IRO-006-5, Requirement R1 – This requirement is not identified in the SAR for this project and will not be proposed for retirement.

MOD-020-0, Requirement R1 – We disagree that MOD-031-2 and IRO-010-2 do not give the necessary entities the authority to request the relevant information and that those standard do not also require the associated entities to provide that information. Demand-Side Management data is necessarily related to the near-term operating time horizon, as well as the planning time horizons, but not to the real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4 R1 and R2, and IRO-001-4 R1, the RC, BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over demand-side management. They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4 R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0 R1 are sources of DADS data, have access to DADS data, or both.

PRC-004-5(i), Requirement R4: The Standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. The Standard's Guideline and Technical Basis for R4, starting on Page 29, considers due diligence that an entity must make in determining the cause of a Protection System misoperation. The additional requirements suggested are not identified within the SAR, and thus are out-of-scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.

Brandon Gleason - Electric Reliability Council of Texas, Inc. – 2

Answer	No
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) agrees with the recommendations and rationales to retire the following requirements identified in the Standards Authorization Request (SAR):

FAC-008-3 R7, R8

FAC-013-2 R1, R2, R4, R5, R6 (All)

INT-004-3.1 R1, R2, R3 (All)

TOP-001-4 R19, R22

ERCOT does not oppose the retirement of the following requirements identified in the SAR, but does not necessarily agree with each stated rationale articulated in support of retirement:

BAL-005-1 R4, R6

COM-002-4 R2

EOP-005-3 R8

EOP-006-3 R7

INT-006-4 R3.1, R4, R5

INT-009-2.1 R2

INT-010-2.1 R1, R2, R3 (All)*

IRO-002-5 R1, R4, R6

IRO-008-2 R6

IRO-014-3 R3

IRO-017 R3

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All)

MOD-001-2 R1, R2, R3, R4, R5, R6 (All)

MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All)

MOD-008-1 R1, R2, R3, R4, R5 (All)

MOD-020-0 R1 (All)

MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All)

MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All)

MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All)

PRC-015-1 R1, R2, R3 (All)

PRC-018-1 R1, R2, R3, R4, R5, R6 (All)

TOP-001-4 R16, R17

VAR-001-4.2 R2, R3

VAR-001-4.2 E.A.15

*Because INT-009-2.1 R1 refers to INT-010-2, it may be preferable to defer consideration of the retirement of the requirements in INT-010-2 to Phase II of Standards Efficiency Review.

ERCOT does not agree with the recommendation and rationale to retire the following standard identified in the SAR for the reasons stated below:

PRC-004-5(i) R4

ERCOT does not support the outright retirement of PRC-004-5(i) Requirement R4 because to do so would eliminate the requirement to investigate in its entirety. However, ERCOT agrees that the requirement as written may impose unnecessary burden by requiring repeated investigations despite the potential inability of a Transmission Owner, Generator Owner, or Distribution Provider to identify the cause(s) of a Misoperation.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SER SDT will be updating rationales on proposed retirements as the project progresses.
The SER SDT agrees that Requirement R4 and R6 of **BAL-005-1** be retained, as both requirements are specific to the calculation of the ACE. The TOP-010-1(i) R2 covers ACE with the wording of “analysis functions and Real-time monitoring” but does not cover specifics such as quality flags for missing or invalid data that is part of the requirement for BAL-005-1 R4 or the accuracy of scan rates that is part of BAL-005-1 R6.

In TOP-010-1(i) R2 (revised from TOP-010-1) the requirement R2 covers the calculation and monitoring of ACE, while the language “ Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring” this is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) the requirement R4 states “The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. Requirement R6 of BAL-005-1 states “Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each Balancing Authority Area. Both of these requirements are specific to identifying missing or invalid data plus scan rates not just the quality of the Real-time data.

The SER Phase I SDT will communicate the SR Phase II SAR DT regarding Requirement R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i) R2 that would satisfy the missing or invalid data plus scan rates and if there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be able to be looked at for retirement within the project or in a future project.

INT-009-2.1, Requirement R2: This requirement can be retired under Paragraph 81 criteria, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7.

PRC-004-5(i), Requirement R4: Removing this requirement from the standard does not preclude entities from conducting any and all investigative actions necessary. Accountability of an entity’s rigor and due diligence will be evident in compliance with the other Standard Requirements.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

A. BPA appreciates the opportunity to comment to the NERC Standards Effectiveness Review (SER) team on the path forward specifically concerning MOD-001-2 and the associated MOD standards (MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3.) BPA does not support the recommendation that NERC withdraw the February 10, 2014 petition to FERC related to MOD-001-2. Although NAESB completed the WEQ-023 Modeling Business Practice Standards which was based on a request from NERC to NAESB to address changes to the NERC MOD-001-2 Reliability Standards not yet ratified by FERC, FERC has not ratified the NAESB BPs. BPA supports the overall effort to migrate the commercial and business aspects of the NERC MOD Reliability Standards into corresponding NAESB Business Practice Standards, a position BPA filed on 09/26/16 in response to the FERC Notice of Proposed Rulemaking (156 FERC ¶ 61,055). In that NOPR, FERC makes clear that the status of the NAESB WEQ-023 Modeling standards and the NERC MOD-001-2 standards are now intertwined. Both are under consideration as part of FERC's overall inquiry into ATC calculations. This includes Docket No. RM14-7-000, dealing with the original February 10, 2014 petition, as well as a related inquiry into ATC from Docket No. AD15-5-000. BPA recommends FERC address the overall ATC topic currently pending these dockets. FERC guidance on the overall direction of ATC standards is overdue and essential before NERC and/or NAESB invest further resources into companion standards. Because only Regulated utilities fall under the purview of the NAESB business practices, BPA urges NERC to closely collaborate with NAESB so there is a joint recommendation moving forward to FERC if NERC intends to proceed with modifying its approach to the February 10, 2014 petition.

B. BPA disagrees with the retirement of INT-004-3.1. NAESB Business Practice Standard WEQ-004 version 3.1 and FERC Docket RM05-5-25 are pending FERC approval. Additionally, NAESB Business Practices are not enforceable. Finally, the Pseudo-Tie Coordination Reference Document is just that, a reference document, and also not enforceable.

C. BPA supports the retirement of all other requirments in scope.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
INT-004-3.1, Requirements R1, R2, R3: This standard may be retired since it satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice.' Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity, has been removed from the list of NERC Functional Entities, supporting the market-based observations herein. R3 specifically refers to "Pseudo-Ties that are included in the NAESB Electric Industry Registry," reinforcing the tie to NAESB WEQ Business Practice Standards.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and proposed MOD-001-2 – ATC/AFC, as well as tags (or eTags) are commercially-focused elements, facilitating interchange and balancing of interchange. The real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where they stated, "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 order, where they stated, "we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI supports the comments provided by NRECA.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see responses to NRECA.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Phase I calls for the full retirement of FAC-013-2, it is noted by the NSRF that the current NERC Project 2015-09 is proposing FAC-013-3. The NSRF asks whether FAC-013-3 needs to be referenced from the SAR for future handling, should the FAC-013 -2 retirement be successful.

Similar situation with VAR-001-4.2 E.A. 15. The NSRF notes that VAR-001-5, which has been approved by the NERC Board of Trustees, contains E.A. 15 in Attachment 1. Does VAR-001-5 E.A.15 need to be referenced from the SAR for future handling, should the VAR-001-4.2 E.A. 15 retirement be successful?

Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 6, Tay Sing
Dislikes 0	

Response

Thank you for your comments.
The SDT will collaborate with the Project 2015-09 drafting team regarding FAC-013-3.
EA 15 was retired from VAR-001-5, which became effective January 1, 2019.

Thomas Foltz - AEP - 3,5

Answer	Yes
Document Name	

Comment

AEP supports the work and overall recommendations of the Standards Drafting Team with the following qualifiers:

AEP does not agree that PRC-004-5(i) R4 meets the drafting team's "Evaluation Criteria for Retiring Reliability Standards Requirements", as the declaration of "no cause found" is made only within this obligation (i.e. "is not redundant"). Regarding the reliability rationale, we would agree that not all investigative actions in and of themselves improve reliability, however the ability to track investigative actions over an extended period of time ensures more riguer is applied to the investigative progress.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Retiring this requirement from the standard does not preclude entities from conducting any and all investigative actions necessary. Accountability of an entities rigor and due diligence will be evident in compliance with the other Standard Requirements.

PRC-004-5(i), Requirement R4: The Standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. The Standard's Guideline and Technical Basis for R4, starting on Page 29, considers due diligence that an entity must make in determining the cause of a Protection System misoperation. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work. Removing a requirement does not preclude an entity from tracking over a period of time.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SMEs, there were no voiced concerns.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Larry Watt - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

We agree with the following comments submitted by TAPS:

We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1

This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2

Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3

This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3

Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3

The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4

IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5

This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3

Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2

This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9

Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)

This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1

In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5

Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5

For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1

The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5

Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see responses to TAPS comments. The additional requirements suggested are not identified within the SAR, and thus are out of scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.

Patricia Boody - Lakeland Electric - 1,3,5,6

Answer	Yes
Document Name	

Comment

I support the comments submitted by TAPS and the FMPA.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see responses to TAPS.

Joe McClung - JEA - 1,3,5 - FRCC

Answer	Yes
Document Name	

Comment

JEA appreciates the effort of the SER Team and agrees with the recommendations and rationales to retire the proposed requirements with the exception of two comments:

1. JEA disagrees with the rationale for the retirement of PRC-004-5(i) R4. This requirement applies only when the cause of a Misoperation has not been determined and requires the TO/GO/DP to perform investigative actions every two quarters until a cause is identified OR a declaration is made that no cause was identified.

a) The SAR states, “Requirement R4 acts as a control to support compliance with requirements R1 & R3.” However, R4 is not a control for determining “whether its Protection System component(s) caused a Misoperation”, but is the next step if the cause of a Misoperation, “for a Misoperation identified in accordance with Requirement R1 or R3”, has not been determined.

b) The SAR also states, “It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a mis-operation”, but this is more than just in the best interest of the entity. R1 requires the entity to “identify whether its Protection System component(s) caused a Misoperation.”

c) The SAR also states, “However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause.” But, investigative actions do improve reliability if they result in the identification of a cause. If no cause is identified, the TO/GO/DP can simply declare that no cause was identified, thereby satisfying the requirement.

There may be valid reasons for retiring this requirement (milestone tracking doesn’t improve reliability, this is a typical best practice, etc.), but the reasons listed above are not valid based upon the current standard language.

2. JEA disagrees with the rationale for the retirements of COM-002-4 R2, EOP-005-3 R8, and EOP-006-3 R7. These requirements are not duplicated in the current version of PER-005-2. PER-005-2 R1.1 allows for the RC, BA, and TOP to create a list of BES “company-specific Real-time reliability-related tasks based on a defined and documented methodology”, but, if specific tasks are intended, then they should be stated directly. It’s implied that these reliability-related tasks would include communication protocols and system restoration, but PER-005-2 only requires a methodology to be followed rather than setting forth explicit minimum competency requirements which is what the requirements proposed for retirement include.

Furthermore, there is clear distinction between the “initial training” of COM-002-4 R2 which occurs “prior to that individual operator issuing an Operating Instruction” and the continuous learning of PER-005-2.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

PRC-004-5(i) Requirement R4:

Removing the requirement from the standard does not preclude entities from conducting any and all investigative actions necessary. The rigor and due diligence of the actions taken to identify the cause of Misoperations will be evident in compliance with the other Standard Requirements. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.

EOP-005-3, Requirement R8 and EOP-006-3 Requirement R7:

The SER SDT agrees that Requirement R8 of EOP-005-3be retained. The SER SDT also believes that Requirement R7 of EOP-006-3 be maintained. The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training.

In PER-005-2 (revised from PER-005-1), the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

The SDT team believes a specific requirement for system restoration training should be maintained, because while a system shutdown is low probability, it could have a high impact if not done properly The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training; and, if there is that opportunity, then Requirement R8 of EOP-005-3 and Requirement R7 in EOP-006-3 may be able to be looked at for retirement within that project or in a future project. If certain elements are essential within an entity's training program, those elements should be explicitly identified in a future version of PER-005 prior to retiring from other standards; such as those identified in EOP-005 and EOP-006.

COM-002-4 Requirement R2:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I SDT will communicate with the SER Phase II SAR DT regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to training on communications protocols; and, if there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or in a future project.

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

COM-002-4 R2 –Requires initial training on communication protocols; NERC proposes that R2 be retired as this topic should be covered in a PER-005-2 compliant Systematic Approach to Training program. Training on ATC communication protocols and tasks to issue and receive op instructions are part of the SCO initial training program. As such, we agree with retirement of COM-002-4 R2.

EOP-005-3 R8 – requires annual system restoration training; NERC proposes that R8 be retired as this topic should be covered in a PER-005-2 compliant Systematic Approach to Training program. Agree as we have three tasks in regards to PSR in the SCO initial training program. Our continuing education program also has annual PSR training (classroom and DTS). As such, we agree with retirement of EOP-005-3 R8.

TOP-001-4 R16-NERC Certified Operators can be addressed through Certification Program and authority is part of the qualification. PER-005-2 training supports this. As such, we agree with retirement of TOP-001-4 R16.

TOP-001-4 R19: the language used to describe how this is managed is through requirements in TOP-003-3 and TOP-002-4. As such, we agree with retirement of TOP-001-4 R19.

VAR-001-4 R2: TOP-001 and TOP-002 require the Transmission Operator to identify System Operating Limit exceedances during real-time and next-day conditions, respectively. System Operating Limits include voltage limits and management of reactive resources as described in VAR-001-4 R2 is fulfilled by acting according to the TOP standards. As such, we agree with retirement of VAR-001-4 R2.

VAR-001-4 R3: The directive in VAR-001-4.2 R3 is fulfilled as a result of compliance with TOP-001-3 R1, R12 and R14; in that the obligation in R1 to maintain the reliability of its operator area is unachievable by the TO if it does not operate devices to regulate voltage and reactive flow; additionally, TOP-001 R 12 and R14 cover addressing System Operating Limits and Interconnection Reliability Operating Limits, where the definition includes voltage stability ratings and system voltage limits. As such, we agree with retirement of VAR-001-4 R3.

Likes 0	
Dislikes 0	

Response

Thank you for your comments and support. However, based on the comments received and the SAR SDT's analysis, the SAR SDT does not intend to propose the following Reliability Standard Requirements for retirement: EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; COM-002-4, Requirement R2; TOP-001-4**,** Requirement R16; and VAR-001-5, Requirement R3.

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3,4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
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 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6, Group Name Exelon Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruth Miller - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

2. Do you agree that NERC should proceed with this project?

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Definitely.	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes NERC should proceed with this project in an effort to identify those current reliability standards that either are duplicative in nature or have little to no impact on improving reliability of the system.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG enthusiastically supports NERC for seeking to eliminate and modify standards requirements to improve their effectiveness and efficiency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patricia Boody - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
I support the comments submitted by TAPS and the FMPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
While we disagree with some of the recommendations of the SDT, we agree that the project has merit, and should proceed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

FMPA agrees with the following comments submitted by TAPS:

We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1

This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2

Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3

This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3

Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3

The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4

IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5

This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3

Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2

This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9

Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)

This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1

In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5

Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5

For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1

The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5 **Duplicative of other standards requiring data provision.**	
Likes 0	
Dislikes 0	
Response Thank you for your support. The additional requirements suggested are not identified within the SAR, and thus are out-of-scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.	
Thank you for your comments. Please see responses to comments provided by TAPS. The additional requirements suggested are not identified within the SAR, and thus are out-of-scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.	
Rebecca Baldwin - Transmission Access Policy Study Group - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

TAPS appreciates the work of the Standards Efficiency Review Teams in developing this SAR. We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired either as part of this SAR or in Phase 2, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)
Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3
R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4
R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7
There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3
Verify through NERC Certification program.

EOP-008-2 R2
Verify through NERC Certification program.

EOP-008-2 R3, R4
NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2
This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1
R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts
R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts
R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4
This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5
This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6
This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5
Inherent in R1.

FAC-003-4 R4
R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6
Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which

captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1
This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2
Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3
This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3
Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3
The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4
IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5
This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3
Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2
This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9
Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)
This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1
In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2
Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6
Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)
Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5
Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5
For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1
The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7
Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3
Requirement language is poorly worded because it is not specifically tied to Operating Instructions issued under TOP-001-4 R1 (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8
Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9
EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13
TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21
R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24
R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3
The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7
Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1
Administrative.

VAR-001-4.1 R1
Duplicative of FAC-014.

VAR-001-4.2 R5
All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3
Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4
Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5
Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see responses provided to your comments in Question 1. The additional requirements suggested are not identified within the SAR, and thus are out-of-scope for this project. Your comment will be referred to the Standards Efficiency Review Team for consideration in a future phase of their work.

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

Answer	Yes
Document Name	

Comment

On behalf of our City Light SMEs, we believe these requirements should be retired.

Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation applauds this effort to retire duplicate and unnecessary requirements, and suggests a future project to consolidate additional requirements and evaluate the NERC Glossary of Terms for clarity and efficiency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
there is value examining the standards/requirements after 10 years of being enforceable. Data requests may be enforced by NERC Rules of Procedure Section 1600. A company's compliance culture is known now along with their internal controls. It makes sense to alleviate administrative burdens by a comprehensive review approach. We applaud NERC for this important effort.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
William Sanders - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Joe McClung - JEA - 1,3,5 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Larry Watt - Lakeland Electric - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruth Miller - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Scanlon - Exelon - 1,3,5,6, Group Name Exelon Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Unofficial Nomination Form

Standards Efficiency Review Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for Standards Efficiency Review (SER) drafting team (DT) members. Nominations must be submitted by **8 p.m. Eastern, Monday, September 17, 2018.**

Additional information is available on the project page. If you have questions, contact Laura Anderson (via email) or at 404-446-9671.

Project Scope

Many NERC Reliability Standards have been mandatory and enforceable for 10+ years in North America. Phase 1 of the SER project and its resulting Standards Authorization Request (SAR) sought to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden. Based on the analyses, the SER teams are recommending the requirements listed in the SAR to be retired. The SER teams maintained that these requirements can be retired without impacting any other standards; i.e., no modifications to other requirements in other standards are necessary.

The SER DT should be composed of individuals that, combined, represent a broad range of experience, including: compliance, engineering, operations, planning, and legal. Having a team made up of cross-functional expertise will allow for more comprehensive inputs from multiple viewpoints.

SER Team Scope

- Collaborate and communicate with a cross-functional team of industry experts on a time-sensitive project timeline
- The SAR was developed using an assessment tool that included criteria & questions to identify candidate requirements that are not essential for reliability, that could be simplified or consolidated, and that could thereby reduce regulatory obligations and/or compliance burden
- Based on the SER SAR team analyses and recommendations, retiring the requirements set out in the SAR
- Flexible schedule and availability are important considering the timeline

Information about you, the nominator. Self-nominations are permitted.			
1. Name	Your first and last name.		
2. E-mail Address	Your email address.		
3. Phone Number	Your phone number.		
4. Title	Your title.		
5. Employer	Who you work for or represent.		
Information about the person you are nominating, the nominee.			
6. Name	Nominee’s name.		
7. E-mail Address	Nominee’s email address.		
8. Phone number	Nominee’s phone number.		
9. Title	Nominee’s business title.		
10. Employer	Who the nominee works for or represents.		
11. Willingness to serve	Has the nominee been contacted to verify willingness to serve on the team?	Yes ☐	No ☐

Provide a brief summary of the nominee’s qualifications for the SER DT position. The summary should be no longer than a single page of single-spaced text.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Standards Efficiency Review Drafting Team

Nomination Period Open through September 17, 2018

Now Available

Nominations are being sought for Standards Efficiency Review drafting team members. Nominations must be submitted by **8 p.m. Eastern, Monday, September 17, 2018**.

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

Next Steps

The Standards Committee is expected to appoint members to the team mid-October 2018. Nominees will be notified after they have been selected.

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-4
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

R7. Reserved.

M7. Reserved.

---

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R8. Reserved.

M8. Reserved.

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. Compliance Monitoring and Enforcement Processes:

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.3. 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 Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.

- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- If a Generator Owner or Transmission Owner 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 and all subsequent compliance records.

1.4. 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	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
R4. Reserved.				
R5. Reserved.				

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7. Reserved.				
R8. Reserved.				

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	TBD	Adopted by NERC Board of Trustees	R7 and R8 and associated elements approved by NERC Board of Trustees for retirement as part of Project 2018-03 Standard Efficiency Review Retirements

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-~~3~~4
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** ~~The first day of the first calendar quarter that is twelve months beyond the date approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter twelve months following BOT adoption~~See Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.~~Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)~~

M4. Reserved. ~~Each Transmission Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement 4. The Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its documentation for determining its Facility Ratings or its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement R4. (Retirement approved by NERC BOT pending applicable regulatory approval.).~~

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R5. Reserved. ~~If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)~~

M5. Reserved.~~If the Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology or a Generator Owner's documentation for determining its Facility Ratings, the Transmission Owner or Generator Owner shall have evidence, (such as a copy of a dated electronic or hard copy note, or other comparable evidence from the Transmission Owner or Generator Owner addressed to the commenter that includes the response to the comment,) that it provided a response to that commenting entity in accordance with Requirement R5. (Retirement approved by NERC BOT pending applicable regulatory approval.)~~

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

R7. Reserved.~~Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

M7. Reserved.~~Each Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R7.~~

R8. Reserved.~~Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely~~

~~and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~As scheduled by the requesting entities:~~

~~**8.1.1.** Facility Ratings~~

~~**8.1.2.** Identity of the most limiting equipment of the Facilities~~

~~**8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:~~

~~**8.2.1.** Identity of the existing next most limiting equipment of the Facility~~

~~**8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.~~

M8. Reserved.~~Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.~~

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. Compliance Monitoring and Enforcement Processes:

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations

- Complaints

1.3. 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 Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.
- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- ~~The Generator Owner and Transmission Owner shall each keep evidence for Measure M4, and Measure M5, for three calendar years. (Retirement approved by FERC effective January 21, 2014.)~~
- ~~The Generator Owner shall keep evidence for Measure M7 for three calendar years.~~
- ~~The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.~~
- If a Generator Owner or Transmission Owner 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 and all subsequent compliance records.

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	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				• 2.2.4
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved. ~~(Retirement approved by FERC effective January 21, 2014.)~~	~~The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.~~	~~The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.~~	~~The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.~~	~~The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)~~
R5. Reserved. ~~(Retirement approved by FERC effective January 21, 2014.)~~	~~The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)~~	~~The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request.~~ ~~OR~~ ~~The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings methodology or Facility~~	~~The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request.~~ ~~OR~~ ~~The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility~~	~~The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		~~Ratings documentation but did not indicate why no change will be made. (R5)~~	~~Ratings documentation. (R5)~~	
R6.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7. Reserved.	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days.~~ ~~OR~~ ~~The Generator Owner failed to provide its Facility~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Ratings to the requesting entities.~~
R8. Reserved.	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2)~~ ~~OR~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~to 35 calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)~~

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	TBD	Adopted by NERC Board of Trustees	R7 and R8 and associated elements approved by NERC Board of Trustees for retirement as part of Project 2018-03

			Standard Efficiency Review Retirements

A. Introduction

1. **Title:** Evaluation of Interchange Transactions
2. **Number:** INT-006-5
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Service Provider
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

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 Balancing Authority shall maintain evidence to show compliance with R1 and R3 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider 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.

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4. Reserved.						
R5. Reserved.						

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	
5	TBD	Adopted by the NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and $\leq$1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		$\leq$ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and $\leq$1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		$\leq$ 3 minutes after receipt of Confirmed Interchange

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - All reliability entities involved in the Arranged Interchange are valid.
  - Generation source and Load sink are defined.
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
  - Distribute notification as each entity approves or denies an Arranged Interchange.
  - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
  - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange
- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

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 R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny

for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:
TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

A. Introduction

1. **Title:** Evaluation of Interchange Transactions
2. **Number:** INT-006-~~4~~5
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider
5. **Effective Date:** ~~First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~See Implementation Plan.

~~6. **Background:** This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.~~

~~The content of INT-006-4 has been revised and expanded in the following manner:~~

- ~~R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.~~
- ~~R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.~~
- ~~R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.~~
- ~~R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.~~

- ~~R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.~~
- ~~Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.~~

B. Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**3.0.** If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.~~

~~M4.~~M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request. ~~and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)~~

R4. Reserved.~~Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

- ~~It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.~~
- ~~It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.~~
- ~~It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.~~

~~M8.~~M4. Reserved. ~~Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)~~

R5. Reserved.~~For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

~~**9.0.** The Source Balancing Authority,~~

~~**10.0.** Each Intermediate Balancing Authority,~~

~~**11.0.** Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,~~

~~**12.0.** Each Transmission Service Provider included in the Arranged Interchange, and~~

~~**13.0.** Each Purchasing Selling Entity included in the Arranged Interchange.~~

~~M14.~~M5. Reserved.~~Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)~~

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 Balancing Authority shall maintain evidence to show compliance with R1~~,~~ and R3~~, R4, and R5~~ for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider 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.

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.~~, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.~~	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved.	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.~~
R5. Reserved.	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.~~	~~The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.~~ ~~OR~~ ~~The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.~~

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	
5	TBD	Adopted by the NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 9 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
<1 hour and $\geq$ 15 minutes prior to ramp start	On-time		$\leq$ 10 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
$\geq$ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		$\geq$ 39 minutes prior to ramp start
$\geq$ 4 hours prior to ramp start	On-time		$\leq$ 2 hours from Arranged Interchange receipt		$\geq$ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time $\geq$ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		$\geq$ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange
- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

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 R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny

for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:
TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

A. Introduction

1. **Title:** Implementation of Interchange
2. **Number:** INT-009-3
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**
   4.1. Balancing Authority
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

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 Balancing Authority shall maintain evidence to show compliance with R1 and R3 for the most recent 3 months plus the current month.

   If a Balancing Authority 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.

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2. Reserved.						
R3.	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	
3	TBD	Adopted by NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

A. Introduction

1. **Title:** Implementation of Interchange
2. **Number:** INT-009-~~2.1~~3
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**

   4.1. Balancing Authority
5. **Effective Date:** See Implementation Plan
6. ~~**Background:** This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.~~

   ~~The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.~~

   ~~The content of INT-009-2 has been revised and expanded in the following manner:~~

   - ~~R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.~~
   - ~~R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.~~
   - ~~R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.~~

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. Reserved.~~The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]~~

M2. Reserved.~~The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)~~

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

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 Balancing Authority shall maintain evidence to show compliance with R1~~, R2~~ and R3 for the most recent 3 months plus the current month.

   If a Balancing Authority 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.

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2. Reserved.	~~Real-time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	
3	TBD	Adopted by NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

~~Guidelines and Technical Basis~~

~~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 R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.~~

A. Introduction

1. **Title:** Reliability Coordination – Monitoring and Analysis
2. **Number:** IRO-002-6
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. Reserved.

M1. Reserved.

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 R2 and R4 and Measures 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. Reserved.				
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 capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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

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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

Version	Date	Action	Change Tracking
6	TBD	Adopted by the NERC Board of Trustees	R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of IRO-002-4 in Project 2014-03 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.

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: (*note*: R1 proposed for retirement in IRO-002-6 as part of Project 2018-03 Standard Efficiency Review Retirements)

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 and IRO-002-6):
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-~~5~~6
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. Reserved.~~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. Reserved. ~~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. Reserved.	~~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	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
			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 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	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 unsuccessful test, initiated action to restore the redundant functionality in more than 4	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 functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6	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; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	hours and less than or equal to 4 hours.	hours and less than or equal to 6 hours.	hours and less than or equal to 8 hours.	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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~~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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

6	TBD	Adopted by the NERC Board of Trustees	R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

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 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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: (*note*: R1 proposed for retirement in IRO-002-6 as part of Project 2018-03 Standard Efficiency Review Retirements)
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 and IRO-002-6):
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:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-6
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1 Transmission Owner

    4.1.2 Generator Owner

    4.1.3 Distribution Provider

    4.2. Facilities:

    4.2.1 Protection Systems for BES Elements, with the following exclusions:

    4.2.1.1 Non-protective functions that are embedded within a Protection System.

    4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

    4.2.1.3 Special Protection Systems (SPS).

    4.2.1.4 Remedial Action Schemes (RAS).

    4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

    4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

    4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

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

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Reserved.

M4. Reserved.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall

implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, and R3, Measures M1, M2, and M3 for a minimum of 12 calendar months following the completion of each Requirement.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, and R3, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None**.**

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
R4. Reserved.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6.	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)
6	TBD	Adopted by the NERC Board of Trustees	R4 retired under Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

---

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing

devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

  Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

  1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
  2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
  3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
  4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
  5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
  6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Composite Protection System*

operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element’s Composite Protection System. If a generating unit’s Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an “Unnecessary Trip – During Fault” Misoperation of the generating unit’s Composite Protection System. This event would be a “Slow Trip – During Fault” Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the

Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.

> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line

during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of “Misoperation.”

The “on-site” activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.
In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line’s relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static

voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was

caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

---

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1 or R3, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C

by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

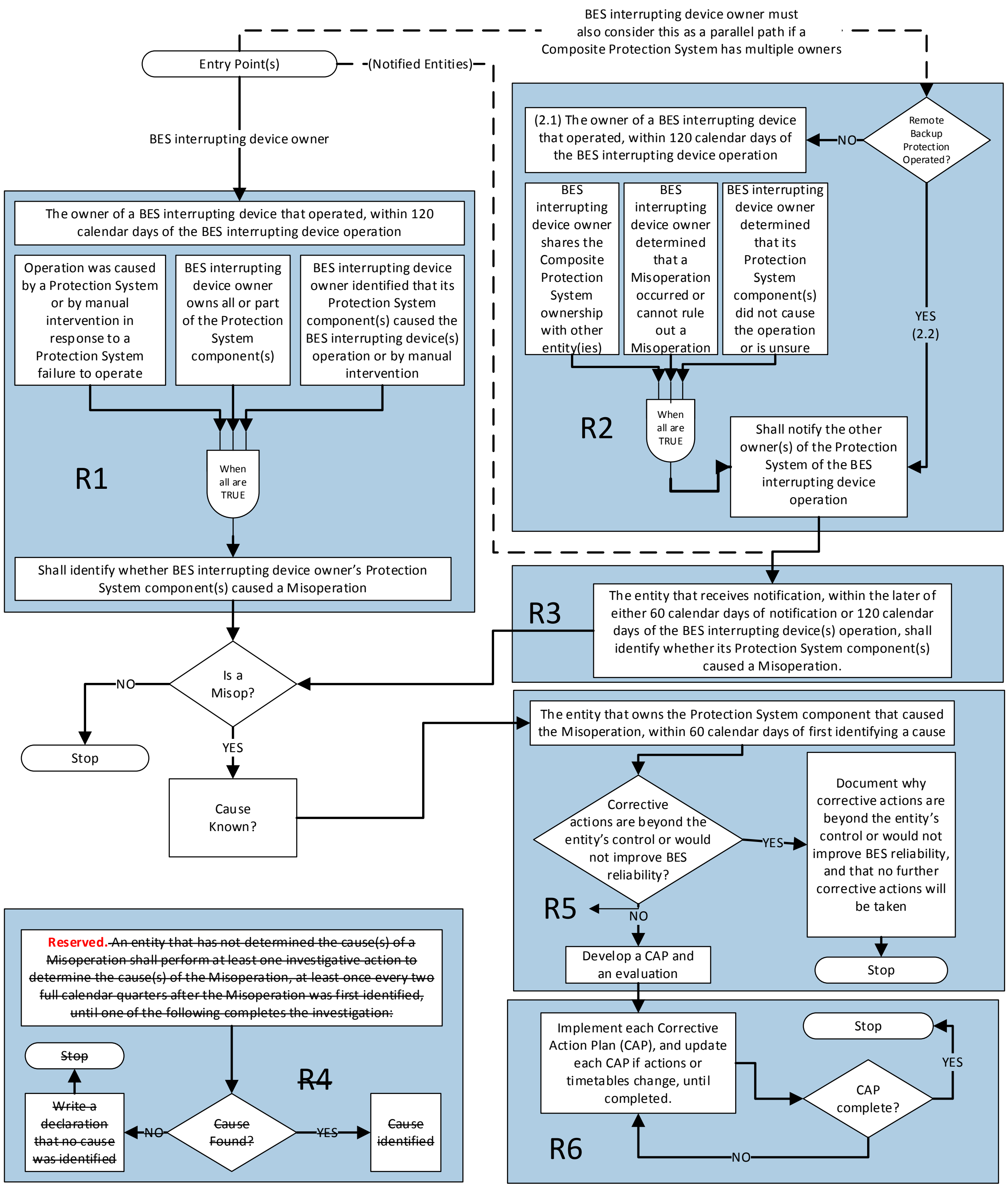
Example R6d: Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-~~5(i)~~6
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See ~~Project 2008-02.2~~ Implementation Plan.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*~~

- ~~The identification of the cause(s) of the Misoperation; or~~
- ~~A declaration that no cause was identified.~~

M4. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.~~

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, and R3~~, and R4~~, Measures M1, M2, and M3~~, and M4~~ for a minimum of 12 calendar months following the completion of each Requirement.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, and R3~~, and R4~~, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

D. ~~Table of Compliance Elements~~Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved.	~~Operations Assessment, Operations Planning~~	~~High~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late.~~ ~~OR~~ ~~The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.~~

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR ~~(See next page)~~

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R5~~	~~(Continued)~~		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6.	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)
6	TBD	Adopted by the NERC Board of Trustees	R4 retired under Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

---

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. ~~Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary.~~ Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. ~~The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.~~

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R1b: A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement~~ ~~R1 and continue its investigation for a cause of the Misoperation~~ under Requirement R4~~. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

~~Requirement R4~~

~~The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.~~

~~A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.~~

~~The following is an example of investigative actions taken to determine the cause of an identified Misoperation:~~

> ~~**Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.~~

~~Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize~~

~~that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.~~

~~The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.~~[8]

~~Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.~~

~~The following are examples of a declaration where no cause was determined:~~

> ~~**Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.~~
>
> ~~**Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.~~

~~[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.~~

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1 or~~,~~ R3~~ or R4~~, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

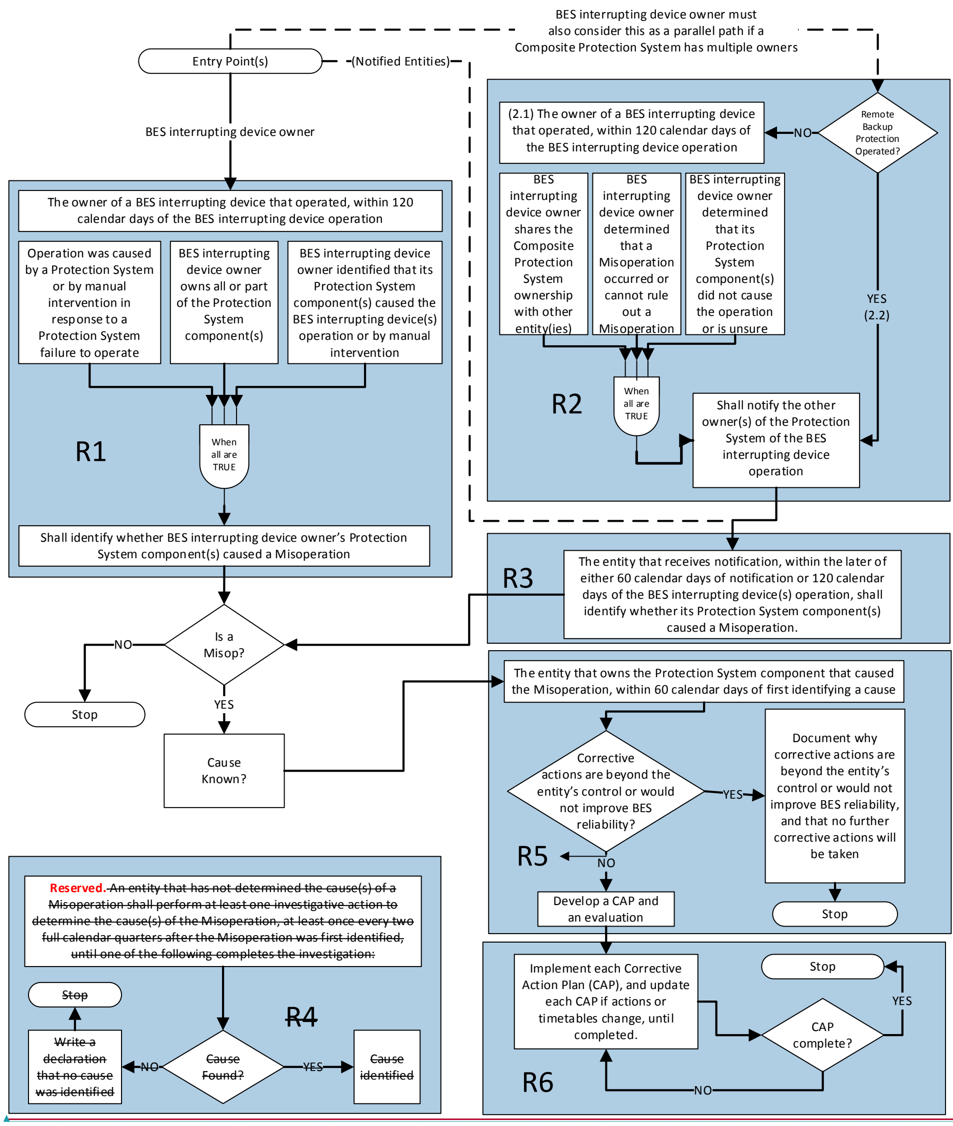
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Field Code Changed

~~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 Introduction~~

~~The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.~~

~~Rationale for Applicability~~

~~Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for "common- mode failure" type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.~~

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-5
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. Reserved.

M19. Reserved.

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. Reserved.

M22. Reserved.

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 R18, and Measure M15 through M18 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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 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	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	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	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	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 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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. Reserved.				
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	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
			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 exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days	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	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	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

R #	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.	redundant functionality in more than 4 hours and less than or equal to 6 hours.	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 at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Authority's primary Control Center, 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 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	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	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	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; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	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 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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the [Project 2014-03] and [Project 2016-01] pages.

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):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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-~~4~~5

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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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~~R18, and Measure M15 through ~~M19~~ M18 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Operator of its inability to comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 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	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	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,	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,

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 required or identified as necessary by the Transmission	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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 any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	for one 30-minute period within that 24-hour period.	minute periods within that 24-hour period.		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.
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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. Reserved.	~~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~~	~~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.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~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 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	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;	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;	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

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 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 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.	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 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 restore the redundant functionality.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R22. Reserved.	~~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.

R #	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	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.			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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

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 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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.~~ [Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:

[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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:** Voltage and Reactive Control

2. **Number:** VAR-001-6

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

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

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.

M2. Reserved.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the

associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to

the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:
"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. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.						
R3.	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	TBD	Adopted by the NERC Board of Trustees	R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R3:

The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate

granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a “tolerance band” as specified in the voltage schedule and the control dead-band in the generator’s excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator’s facility during normal operations, and be based on the TOP’s assessment of N-1 and credible N-2 system contingencies. The voltage schedule’s bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator’s automatic voltage regulator’s control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule’s bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. **Title:** Voltage and Reactive Control

2. **Number:** VAR-001-~~5~~6

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:** ~~The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~See Implementation Plan.

~~C.~~B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.~~Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*~~

M2. Reserved. ~~Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.~~

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

~~D.~~C. Compliance

1. **Compliance Monitoring Process:**

1.1. **Compliance Enforcement Authority:**

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. **Evidence Retention:**

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. **Compliance Monitoring and Assessment Processes:**

“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. **Additional Compliance Information:**
None.

Violation Severity Levels

R #	Time Hori	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.	~~**Real-time Operations, Same-day Operati**~~	~~**High**~~	~~N/A~~	~~N/A~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.~~
R3.	**Real-time Operations, Same-day Operations**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

Formatted Table

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

~~E.~~D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	TBD	Adopted by the NERC Board of Trustees	R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

~~**Rationale for R2:**~~

~~Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.~~

Rationale for R3:

~~Similar to Requirement R2, t~~The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Page 16 of

Rationale for R4:
The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:
The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Page 17 of

A. Introduction

1. **Title:** **Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**
2. **Number:** FAC-013-2
3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.
4. **Applicability:**
   - **4.1. Planning Coordinators**
5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M4. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning 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 Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)

- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods 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 Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3 (Retirement approved by FERC effective January 21, 2013.)	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: FAC-013-2 — Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
FAC-013-2	R1.	04/01/2013		
FAC-013-2	1.1.	04/01/2013		
FAC-013-2	1.2.	04/01/2013		
FAC-013-2	1.3.	04/01/2013		
FAC-013-2	1.4.	04/01/2013		
FAC-013-2	1.4.1.	04/01/2013		
FAC-013-2	1.4.2.	04/01/2013		
FAC-013-2	1.4.3.	04/01/2013		
FAC-013-2	1.4.4.	04/01/2013		
FAC-013-2	1.4.5.	04/01/2013		
FAC-013-2	1.4.6.	04/01/2013		
FAC-013-2	1.4.7.	04/01/2013		
FAC-013-2	1.5.	04/01/2013		
FAC-013-2	R2.	04/01/2013		
FAC-013-2	2.1.	04/01/2013		
FAC-013-2	2.1.1.	04/01/2013		
FAC-013-2	2.1.2.	04/01/2013		
FAC-013-2	2.2.	04/01/2013		
FAC-013-2	R3.	04/01/2013		01/21/2014
FAC-013-2	R4.	04/01/2013		
FAC-013-2	R5.	04/01/2013		
FAC-013-2	R6.	04/01/2013		

A. Introduction

1. **Title:** **Dynamic Transfers**

2. **Number:** INT-004-3.1

3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Purchasing-Selling Entity

5. **Effective Date:**

   See implementation plan.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

[1] Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority 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 Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

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	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services	Attaining BA	Native BA

FERC OATT Schedules 3–6 and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

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 R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

3	June 30, 2014	FERC letter order issued approving INT-004-3	
3.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
3.1	November 26, 2014	FERC letter order approving errata changes.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: INT-004-3.1 — Dynamic Transfers

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
INT-004-3.1	All	11/26/2014		

A. Introduction

1. **Title: Interchange Initiation and Modification for Reliability**
2. **Number: INT-010-2.1**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority

5. **Effective Date:**

   See implementation plan.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority 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 Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

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 R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised
2	June 30, 2014	FERC letter order issued approving INT-010-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: INT-010-2.1 — Interchange Initiation and Modification for Reliability

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
INT-010-2.1	All	11/26/2014		

A. Introduction

1. **Title:** **Available Transmission System Capability**
2. **Number:** **MOD-001-1a**
3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
   - **4.2.** Transmission Operator.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall select one of the methodologies[1] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*[*Time Horizon: Operations Planning*]

R2.1. Hourly values for at least the next 48 hours.

R2.2. Daily values for at least the next 31 calendar days.

R2.3. Monthly values for at least the next 12 months (months 2-13).

R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3.1. Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:

---

[1] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

R3.2.2. A rationale for that accounting specified in R3.2.

R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

R3.4. The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

R3.6.3. How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4.1. Each Planning Coordinator associated with the Transmission Service Provider’s area.

R4.2. Each Reliability Coordinator associated with the Transmission Service Provider’s area.

R4.3. Each Transmission Operator associated with the Transmission Service Provider’s area.

R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider’s area.

R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

R8.2. Daily values, once per day.

R8.3. Monthly values, once per week.

R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Dispatch Order
- Participation Factors
- Block Dispatch

- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

R9.1. The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

C. Measures

M1. The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

M2. The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

M3. The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

M4. The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

M5. The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

M6. The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning.

When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

M7. The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

M8. The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

M9. The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider 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 Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.

- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.
R2.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours. ▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours. ▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours. ▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours. ▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days. ▪ Has calculated monthly ATC or AFC values for less than the next 4 months. ▪ Did not use the selected methodology(ies) to calculate ATC.
R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago. **OR** The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago. **OR** The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation. **OR** The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation.
R5.	N/A	N/A	N/A	The Transmission Service Provider did not make the ATCID available to the parties described in R4.
R6.	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	than 3 ATC Paths or Flowgates (whichever is greater).
R8.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R9	N/A	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request.	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request.	The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request.

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by the Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R2 and R8	Interpretation (Project 2009-15)
1a	1/14/2016	Corrected VRF designations from Lower to Medium for the following requirements based on Docket No. RM08-19-002: R1, R2, R3, R6, R7, R8, R9	

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. The second part of NYISO’s question is only applicable if the first part was answered in the

negative and therefore will not be addressed.

Requirement Number and Text of Requirement

MOD-029-01 Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff." PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.
Question #2
Could OS_F in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?
Response to Question #2
This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-001-1a — Available Transmission System Capability

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-001-1a	All	04/01/2011		

A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

4. **Applicability:**

   4.1. Load-Serving Entities.

   4.2. Resource Planners.

   4.3. Transmission Service Providers.

   4.4. Balancing Authorities.

   4.5. Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-term Planning*]

R1.1. The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.

R1.2. The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.

R1.3. The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.

R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3. Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Medium]* [*Time Horizon: Operations Planning*]

R3.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R3.2. Identifying expected import path(s) or source region(s).

R4. Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R4.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R4.2. Identifying expected import path(s) or source region(s).

R5. At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R5.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area

- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider’s area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R5.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

R6. At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]

R6.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner’s area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner’s area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner’s area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R6.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

R7. Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider’s system of the amount of CBM set aside. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R8. Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

R9.1. Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.

R9.2. To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.

R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations*]

R11. When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12. The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity[1]" under an EEA 2 if: [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12.1. The CBM is available

R12.2. The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and

R12.3. The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.

C. Measures

M1. Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

M2. Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

---

[1] See Attachment 1-EOP-002-0 for explanation.

M3. Each Load-Serving Entity that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

M4. Each Resource Planner that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

M5. Each Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (R5)

M6. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years two through ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement. (Note that CBM values may legitimately be zero.) (R6)

M7. Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside. (R7)

M8. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside. (R8)

M9. Each Transmission Service Provider that maintains CBM and each Transmission Planner shall provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R9. (R9)

M10. Each Load-Serving Entity and Balancing Authority shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time it requested to import energy using firm Transfer Capability set aside as CBM, it was in an EEA 2 or higher. (R10)

M11. Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived Real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R11)

M12. Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange meeting the criteria in R12. (R12)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force during the past three calendar years plus the current year to show compliance with R1.
- The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, R5, R7, R9, and R12 for the most recent three calendar years plus the current year.
- The Load-Serving Entity shall each maintain evidence to show compliance with R3 and R10 for the most recent three calendar years plus the current year.
- The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R6, R8, and R9 for the most recent three calendar years plus the current year.
- The Balancing Authority shall maintain evidence to show compliance with R10 and R11 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
- If an entity 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 subsequently submitted audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting

- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address one of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address two of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago. **OR** The Transmission Service Provider that maintains CBM does not have a CBMID; **OR** The CBM maintaining Transmission Service Provider's CBMID does not address three of the sub requirements.
R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID after the effective date of the change, but not more than 30 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 30 or more calendar days but not more than 60 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 60 or more calendar days but not more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to at least one, but not all, of the entities specified in R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to none of the entities specified in R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.		The Load-Serving Entity did not use one of the methods described in R3.1 **OR** The Load-Serving Entity did not identify paths or regions as described in R3.2		The Load-Serving Entity did not use one of the methods described in R3.1 **AND** The Load-Serving Entity did not identify paths or regions as described in R3.2
R4		The Resource Planner did not use one of the methods described in R4.1 **OR** The Resource Planner did not identify paths or regions as described in R4.2		The Resource Planner did not use one of the methods described in R4.1 **AND** The Resource Planner did not identify paths or regions as described in R4.2
R5.	The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available. **OR** The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as	The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM failed to establish an initial value for CBM. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		described in R5.2.		paths or regions as described in R5.2
R6.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 22 months after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM failed to establish an initial value for CBM for each of the years 2 through 10. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		on one or more paths or regions as described in R6.2		R6.1 that was available, and did not base the allocation on one or more paths or regions as described in R6.2
R7.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Service Provider that maintains CBM notified none of the entities as required.
R8.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Planner with	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Planner with an associated Transmission

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			an associated Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	Service Provider that maintains CBM notified none of the entities as required.
R9.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 30, but not more than 45, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 45, but not more than 60, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 60, but not more than 75, days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided at least one, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 75 days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided none of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.
R10.	N/A	N/A	N/A	A Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher.
R11.	N/A	N/A	N/A	A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The Transmission Service Provider failed to approve an Arranged Interchange for CBM that met the criteria described in R12 without a reliability reason to do so.

Version History

Version	Date	Action	Change Tracking
1	February 28, 2014	Updated VRF designations for Requirements R3 and R4 from Lower to Medium based on June 24, 2013 approval.	
1	January 14, 2016	Corrected VRF designations from Lower to Medium for the following requirements based FERC Letter Order dated June 24, 2013: R1, R2, R5, R6, R7	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-004-1 — Capacity Benefit Margin

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-004-1	All	04/01/2011		

A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R1.1. Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions).
- Reserve sharing requirements.
- Inertial response and frequency bias.

R1.2. The description of the method used to allocate TRM across ATC Paths or Flowgates.

R1.3. The identification of the TRM calculation used for the following time periods:

R1.3.1. Same day and real-time.

R1.3.2. Day-ahead and pre-schedule.

R1.3.3. Beyond day-ahead and pre-schedule, up to thirteen months ahead.

R2. Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3. Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

R4. Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R5. The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

C. Measures

M1. Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

M2. Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

M3. Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

M4. Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

M5. Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator 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 Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity 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.

1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.	The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago. **OR** The Transmission Operator's TRMID does not address one of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago. **OR** The Transmission Operator's TRMID does not address two of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more. **OR** The Transmission Operator does not have a TRMID. **OR** The Transmission Operator's TRMID does not address three of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3
R2.	N/A	N/A	N/A	One or both of the following: ▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. ▪ The Transmission Operator included components of CBM in TRM.
R3.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.	The Transmission Operator did not make the TRMID available for 90 days or more.

R4	The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing.	The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not establish TRM OR The last determination of TRM was more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.
R5	The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.	The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing.

Version History

Version	Date	Action	Change Tracking
1	November 24, 2009	MOD-008-1 approved by FERC	
1	January 14, 2016	Corrected VRF designations from Lower to Medium for the following: R1, R2, R4, and R5	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-008-1 — Transmission Reliability Margin Calculation Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-008-1	All	04/01/2011		

A. Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators**

2. **Number:** MOD-020-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-020-0 — Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-020-0	All	06/18/2007		

A. Introduction

1. **Title: Area Interchange Methodology**
2. **Number: MOD-028-2**
3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   - **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- **R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.
- **R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.
- **R1.3.** Any contractual obligations for allocation of TTC.
- **R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.
- **R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:
  - **R1.5.1.** Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation
  - **R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

R1.5.3. The source/sink or POR/POD identification and mapping to the model.

R1.5.4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

R2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3.1. For TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. A daily or hourly load forecast for TTCs used in current-day and next-day ATC calculations.

R3.1.3. A daily load forecast for TTCs used in ATC calculations for days two through 31.

R3.1.4. A monthly load forecast for TTCs used in ATC calculations for months two through 13 months TTCs.

R3.1.5. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4.1. Use all Contingencies meeting the criteria described in the ATCID.

R4.2. Respect any contractual allocations of TTC.

R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.

R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

R6.3. Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations.

---

[1] The Transmission operator may honor distribution factors less than 5% if desired.

R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: *Lower*] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

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.

The Transmission Operator and Transmission Service Provider 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 Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator 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 Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider has an ATCID but it is missing one of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing two of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing more than three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	One or both of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.	One or more of the following: • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period • The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.	daily ATC calculations. • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R9.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 25% of the value calculated in the measure or 25MW, whichever is greater.	more than 35% of the value calculated in the measure or 35MW, whichever is greater.	more than 45% of the value calculated in the measure or 45MW, whichever is greater.	
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the Board of Trustees	
1	July 24, 2013	Updated VSLs based on June 24, 2013 approval.	
2	February 9, 2012	Adopted by the Board of Trustees	
2	July 24, 2013	FERC order issued July 18, 2013 approving MOD-028-2	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-028-2 — Area Interchange Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-028-2	All	10/01/2013		

A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-2a**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-2a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider 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 Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	11/05/2009	Board approved Interpretation of R5 and R6	Interpretation (Project 2009-15)
1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
2a	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
2a	November 19, 2015	FERC Order issued approving MOD-029-2a. Docket No. RM15-13-000.	

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.

The second part of NYISO's question is only applicable if the first part was answered in the negative and therefore will not be addressed.
Requirement Number and Text of Requirement

MOD-029-2a Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff." PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.
Question #2
Could OS_F in MOD-029-2a Requirement R5 and OS_{NF} in MOD-029-2a Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?
Response to Question #2
This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-029-2a — Rated System Path Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-029-2a	All	04/01/2017		

A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-3**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**

    4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.

    4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:

R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

R1.2.3. The source/sink or POR/POD identification and mapping to the model.

R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.2. Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.3. Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

R2.2. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

R2.3. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

R2.4. Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

R2.5. At a minimum, establish the TFC once per calendar year.

R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

R3.3. Updated at least once per month for AFC calculations for months two through 13.

R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:

R6.2.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.7. The impact of other firm services determined by the Transmission Service Provider.

R7. When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.7. The impact of other non-firm services determined by the Transmission Service Provider.

R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

Where:

$\mathbf{AFC_F}$ is the firm Available Flowgate Capability for the Flowgate for that period.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

$Postbacks_{Fi}$ are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{Fi}$ are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

R11. When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$\text{ATC} = \min(\text{P})$$

$$\text{P} = \{\text{PATC}_1, \text{PATC}_2, \ldots \text{PATC}_n\}$$

$$\text{PATC}_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

PATC_n is the partial Available Transfer Capability for a path relative to a Flowgate *n.*

AFC_n is the Available Flowgate Capability of a Flowgate *n*.

DF_{np} is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

M5. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

M13. The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider 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 Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. **OR** The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: • The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not	One or more of the following: • The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.	One or more of the following: • The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.	One or more of the following: • The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2. • The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. • The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	been more than 14 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.	• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.	The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update. • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.	flowgate as described in R2.3. • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. • The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. • The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	One or more of the following: • The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days • The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks	One or more of the following: • The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days • The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks	One or more of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks	One or more of the following: • The Transmission Operator did not update the model per R3.2 for more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than ten weeks • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. • The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.
R4.	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calculated in the measure or 25MW, whichever is greater..	calculated in the measure or 35MW, whichever is greater.	calculated in the measure or 45MW, whichever is greater.	
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Flowgates or 1 Flowgate (whichever is greater).	or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	Flowgates or more than 3 Flowgates (whichever is greater).
R10	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.

A. Regional Differences

None identified.

B. Associated Documents

Version History

Version	Date	Action	Change Tracking
2		Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11	Revised
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving MOD-030-3. Docket No. RM15-13-000.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-030-3 — Flowgate Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-030-3	All	04/01/2017		

A. Introduction

1. **Title:** Available Transmission System Capability

2. **Number:** MOD-001-2

3. **Purpose:**

   To ensure that determinations of available transmission system capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1 Transmission Operator

   4.1.2 Transmission Service Provider

   4.2. Exemptions: The following is exempt from MOD-001-2.

   4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1 Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:

1.1.1 Facility ratings;

1.1.2 System voltage limits;

1.1.3 Transient stability limits;

1.1.4 Voltage stability limits; and

1.1.5 Other System Operating Limits (SOLs).

1.2 Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:

1.2.1 The simulation of transfers performed through the adjustment of generation, Load, or both;

1.2.2 Transmission topology, including, but not limited to, additions and retirements;

1.2.3 Expected transmission uses;

1.2.4 Planned outages;

1.2.5 Parallel path (loop flow) adjustments;

1.2.6 Load forecast; and

1.2.7 Generator dispatch, including, but not limited to, additions and retirements.

1.3 Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe in its methodology the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operator's area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
  - TFC or TTC being determined by one or more limits.
  - Simulation being used to find the maximum TFC or TTC that remains within the limit.
  - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
  - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
  - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
  - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
  - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
  - A description of how the element is used in the determination of TFC or TTC.
- A description of the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, as specified in parts 1.3, 1.3.1, 1.3.2, or 1.3.3).
- Each Transmission Operator that determines TFC or TTC shall provide evidence that currently active TFC or TTC values were determined based on its current written methodology, as specified in Requirement R1.

R2. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC:

2.1.1. The simulation of transfers performed through the adjustment of generation, Load, or both;

2.1.2. Transmission topology, including, but not limited to, additions and retirements;

2.1.3. Expected transmission uses;

2.1.4. Planned outages;

2.1.5. Parallel path (loop flow) adjustments;

2.1.6. Load forecast; and

2.1.7. Generator dispatch, including, but not limited to, additions and retirements.

2.2. Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

M2. Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:

- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
  - o A description of how the element is used in the determination of AFC or ATC.
  - o A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
  - o A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- For each Transmission Service Provider that uses the Flowgate Methodology, a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability-related constraints identified in part 1.3.
- Each Transmission Service Provider that determines AFC or ATC shall provide evidence that currently active AFC or ATC values were determined based on its current written methodology, as specified in Requirement R2.

R3. Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for determining CBM values. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

R4. Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for determining TRM values. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values. *[Violation Risk Factor: Lower][Time Horizon: Operations Planning]*

M4. Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Operator does not maintain TRM.

R5. Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

5.1. A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

5.2. If not publicly posted on OASIS or its company website, the Transmission Operator's effective:

5.2.1 TRMID; and

5.2.2 TFC or TTC methodology.

5.3. If not publicly posted on OASIS or its company website, the Transmission Service Provider's effective:

5.3.1 ATCID; and

5.3.2 CBMID.

M5. Examples of evidence include, but are not limited to:

- Dated records of the request and the Transmission Operator's or Transmission Service Provider's response to the request;
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

R6. Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

6.1.1 Alter the format in which it maintains or uses the data; or

6.1.2 Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.

6.3 If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or

- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity’s request, and the response to the request;
- Dated records of a registered entity’s request, and a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity’s confidentiality, regulatory, or security requirements (6.3) is a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
    - Hourly values for the most recent 14 days;
    - Daily values for the most recent 30 days; and
    - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- "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. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Lower**	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2) OR	Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values. OR Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3) OR Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	**Operations Planning**	**Lower**	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	**Operations Planning**	**Lower**	None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	None.	None.	None.	Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values. OR Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.
R5	**Operations Planning**	**Lower**	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the date of the request, but did respond in writing within 75 calendar days.	the date of the request, but did respond in writing within 105 calendar days.	from the date of the request, but did respond in writing within 135 calendar days.	
R6	**Operations Planning**	**Lower**	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

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 R1:

Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability-related constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.

Rationale for R2:

A TSP must clearly document its methods of determining AFC and ATC so that TOPs or other entities can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate. Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC.

Rationale for R3:

Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose Loads are located on that TSP's system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

Rationale for R4:

Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC and ATC is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of determining TRM.

Rationale for R5:

Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Rationale for R6:

This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP or TSP share their data, with the caveat that the TOP or TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP or TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board of Trustees.	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	February 6, 2014	Adopted by the NERC Board of Trustees.	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-001-2 — Available Transmission System Capability

<u>United States</u>

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-001-2	All			

This standard has not yet been approved by the applicable regulatory authority.

Implementation Plan

Project 2018-03 Standards Efficiency Review Retirements

Applicable Standard(s)

- FAC-008-4 – Facility Ratings
- INT-006-5 – Evaluation of Interchange Transactions
- INT-009-3 – Implementation of Interchange
- IRO-002-6 – Reliability Coordination – Monitoring and Analysis
- PRC-004-6 – Protection System Misoperation Identification and Correction
- TOP-001-5 – Transmission Operations
- VAR-001-6 – Voltage and Reactive Control

Requested Retirement(s)

- FAC-008-3 – Facility Ratings
- FAC-013-2 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- INT-004-3.1 – Dynamic Transfers
- INT-006-4 – Evaluation of Interchange Transactions
- INT-009-2.1 – Implementation of Interchange
- INT-010-2.1 – Interchange Initiation and Modification for Reliability
- IRO-002-5 – Reliability Coordination – Monitoring and Analysis
- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Readability Margin Calculation Methodology
- MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
- MOD-028-2 – Area Interchange Methodology
- MOD-029-2a – Rated System Path Methodology
- MOD-030-3 – Flowgate Methodology
- PRC-004-5(i) – Protection System Misoperation Identification and Correction
- TOP-001-4– Transmission Operations
- VAR-001-5– Voltage and Reactive Control

Requested Withdrawal

- MOD-001-2 – Available Transmission System Capability

Applicable Entities

See subject standards.

Background

In 2017, NERC initiated the Standards Efficiency Review. The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. Following the completion of the first phase of work, the Standards Efficiency Review Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- withdraw a standard, MOD-001-2, that is currently pending approval by applicable governmental authorities.

General Considerations

For Reliability Standards that are proposed to be retired in their entirety (i.e., no new standard version is proposed), this Implementation Plan provides that the retirement shall become effective immediately upon regulatory approval.

For Reliability Standards that are revised to remove requirements, the revised standards will become effective on the first day of the first calendar quarter that is three (3) months after applicable regulatory approval. This implementation timeframe reflects consideration that entities may need time to update their internal systems and documentation to reflect the new standard version numbers.

Effective Date

Reliability Standards FAC-008-4, INT-006-5, INT-009-3, IRO-002-6, PRC-004-6, TOP-001-5, and VAR-001-6

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 (3) 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 (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standards FAC-008-3, INT-006-4, INT-009-2.1, IRO-002-5, PRC-004-5(i), TOP-001-4, and VAR-001-5

The Reliability Standard shall be retired immediately prior to the effective date of the revised standard in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standards FAC-013-2, INT-004-3.1, INT-010-2.1, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-020-0, MOD-028-2, MOD-029-2a, and MOD-030-3

The Reliability Standard shall be retired on the effective date of the applicable governmental authority's order approving retirement of 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 be retired on the date the standard is retired by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2018-03 Standards Efficiency Review Retirements

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2018-03 Standards Efficiency Review Retirements**. Comments must be submitted by **8 p.m. Eastern, Friday, April 12, 2019.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email), or at 404-446-9671.

Background Information

In 2017, NERC initiated the Standards Efficiency Review (SER). The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement of Reliability Standard Requirements. Following the completion of the first phase of work, the SER Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee, which the Standards Committee accepted in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- Retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- Revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- Withdraw a Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities.

Based on the expertise of the Standard Drafting Team (SDT) and from consideration of the comments received in the SAR posting, the SDT considered the recommendations for retirements listed in the SAR and determined that it would not proceed with several of the recommended retirements for the following reasons:

1. The SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include:
    - BAL-005-1, Requirements R4 and R6
    - COM-002-4, Requirement R2

- EOP-005-3, Requirement R8
- EOP-006-3, Requirement R7
- IRO-014-3, Requirement R3
- IRO-017-1, Requirement R3
- VAR-001-5, Requirement R3

2. The SDT is proposing to take no action on two standards already scheduled for retirement.
    - PRC-015-1, Requirements R1, R2 and R3
    - PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6
3. The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit:
    - IRO-002-5, Requirements R4 and R6
        - Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. The inclusion of the Energy Management System (EMS), IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1.
    - IRO-008-2, Requirement R6
        - Although Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance.
    - TOP-001-4, Requirements R16 and R17
        - Requirements R16 and R17 are necessary to make it clear that the System Operator has the authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some Reliability Coordinators may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1.

The SDT created a justification document that is posted as a supporting document on the project page.

Questions

1. The SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include: BAL-005-1, Requirements R4 and R6; COM-002-4, Requirement R2; EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; IRO-014-3, Requirement R3; IRO-017-1, Requirement R3; and VAR-001-5, Requirement R3. Do you agree with the SDT's recommendation that these standards requirements be considered as part of the SER Phase II effort? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT is proposing to take no action on two standards already scheduled for retirement: PRC-015-1, Requirements R1, R2 and R3; and PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6. Do you agree with the SDT's recommendation to take no action for these standards already scheduled for retirement? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit: IRO-002-5, Requirements R4 and R6; IRO-008-2, Requirement R6, and TOP-001-4, Requirements R16 and R17. Do you agree with the SDT's recommendation to retain these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

4. The SDT is proposing to retire FAC-008-3, Requirements R7 and R8. Do you agree with the SDT's proposal to retire these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

5. The SDT is proposing to retire FAC-013-2, Requirements R1, R2, R4, R5 and R6 (all). Do you agree with the SDT's proposal to retire FAC-013-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

6. The SDT is proposing to retire INT-004-3.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-004-3.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

7. The SDT is proposing to retire INT-006-4, Requirements R3.1, R4, and R5. Do you agree with the SDT's proposal to retire Requirements R3.1, R4, and R5 of INT-006-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

8. The SDT is proposing to retire INT-009-2.1, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of INT-009-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

9. The SDT is proposing to retire INT-010-2.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-010-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

   ☐ Yes
   ☐ No

   Comments:

10. The SDT is proposing to retire IRO-002-5, Requirement R1. Do you agree with the SDT's proposal to retire Requirement R1 of IRO-002-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

12. The SDT is proposing to retire MOD-008-1, Requirements R1, R2, R3, R4, and R5 (all). Do you agree with the SDT's proposal to retire MOD-008-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes
☐ No

Comments:

13. The SDT is proposing to retire MOD-028-2, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, and R11 (all). Do you agree with the SDT's proposal to retire MOD-028-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes
☐ No

Comments:

14. The SDT is proposing to retire MOD-029-2a, Requirements R1, R2, R3, R4, R5, R6, R7, and R8 (all). Do you agree with the SDT's proposal to retire MOD-029-2a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes
☐ No

Comments:

15. The SDT is proposing to retire MOD-030-3, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9 and R10 (all). Do you agree with the SDT's proposal to retire MOD-030-3? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes
☐ No

Comments:

16. The SDT is proposing to retire MOD-001-1a, Requirements R1, R2, R3, R4, R5, R6, R7, R8 and R9 (all). Do you agree with the SDT's proposal to retire MOD-001-1a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

17. The SDT is proposing to withdraw Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities. Do you agree with the SDT's proposal to withdraw Reliability Standard MOD-001-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

18. The SDT is proposing to retire MOD-020-0, Requirement R1 (all). Do you agree with the SDT's proposal to retire MOD-020-0? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

19. The SDT is proposing to retire PRC-004-5(i), Requirement R4. Do you agree with the SDT's proposal to retire Requirement R4 of PRC-004-5(i)? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

20. The SDT is proposing to retire TOP-001-4, Requirements R19 and R22. Do you agree with the SDT's proposal to retire Requirements R19 and R22 of TOP-001-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

21. The SDT is proposing to retire VAR-001-5, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of VAR-001-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

    ☐ Yes
    ☐ No

    Comments:

22. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

    Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard FAC-008-4. 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.

VRF Justification for FAC-008-4, Requirement R1

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R2

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R3

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R6

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R1

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R2

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R3

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R6

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-006-5. 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.

VRF Justification for INT-006-5, Requirement R1

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R2

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R3

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R1

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R2

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R3

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard, with the exception of: the reference to communicating a fact within 10 minutes of the denial was deleted to correspond to the retirement of Requirement R3 Part 3.1.

VSLs for INT-006-5, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-009-3. 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.

VRF Justification for INT-009-3, Requirement R1

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VRF Justification for INT-009-3, Requirement R3

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R1

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R3

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard IRO-002-6. 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.

VRF Justification for IRO-002-6, Requirement R2

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-6, Requirement R3

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-6, Requirement R4

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-6, Requirement R5

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-6, Requirement R6

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-6, Requirement R2

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-6, Requirement R3

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-6, Requirement R4

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-6, Requirement R5

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-6, Requirement R6

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard PRC-004-6. 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.

VRF Justification for PRC-004-6, Requirement R1

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R2

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R3

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R5

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R6

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R1

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R2

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R3

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R5

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R6

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard TOP-001-5. 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.

VRF Justification for TOP-001-5, Requirement R1
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R2
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R3
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R4
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R5
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R6
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R7
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R8
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R9
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R10
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R2
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard VAR-001-6. 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.

VRF Justification for VAR-001-6, Requirement R1
The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R3
The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R4
The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R5
The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R6
The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R1
The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R3
The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R4
The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R5
The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R6
The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

Technical Justifications

Project 2018-03 Standards Efficiency Review Retirements

Purpose: The purpose of the Project 2018-03 – Standards Efficiency Review Retirements Technical Justifications document was for the Standards Drafting Team (SDT) to evaluate each recommendation for retirement identified in the Standards Authorization Request (SAR). It is intended to facilitate understanding about the technical rationale for each recommendation proposed by the SDT.

Technical Justifications for Phase I of Standards Efficiency Review - Retirements

BAL-005-1, Requirements R4 and R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes these requirements should be retained for the following reasons:
Requirements R4 and R6 of BAL-005-1 are requirements specific to the calculation of the Area Control Error (ACE). TOP-010-1(i) Requirement R2 covers ACE with the wording of "…analysis functions and Real-time monitoring…" but does not cover specifics, such as: quality flags for missing or invalid data that is part of BAL-005-1, Requirement R4 or the accuracy of scan rates that is part of BAL-005-1, Requirement R6.

In TOP-010-1(i), Requirement R2 (revised from TOP-010-1) covers the calculation and monitoring of ACE, however, the language: "Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring," is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) Requirement R4 states: "The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data." Requirement R6 of BAL-005-1 states: "Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each Balancing Authority Area." Both of these requirements are specific to identifying missing or invalid data plus scan rates, not just the quality of the Real-time data.

The Standards Efficiency Review – Retirements (SER Phase I) team will communicate with the Standards Efficiency Review Phase II team regarding Requirements R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i), Requirement R2 that would satisfy the missing or invalid data plus scan rates. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be able to be looked at for retirement within that project or within a future project.

COM-002-4, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees (BOT) November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2, Requirement R2 that would satisfy the training requirements specific to training on communications protocols. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or within a future project.

EOP-005-3, Requirement R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training. In PER-005-2, the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R8 of EOP-005-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R8 of EOP-005-3 may be able to be looked at for retirement within that project or within a future project.

EOP-006-3, Requirement R7
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training. In PER-005-2, the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R7 in EOP-006-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R7 of EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R7 of EOP-006-3 may be able to be looked at for retirement within that project or within a future project.

FAC-008-3, Requirements R7 and R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these requirements should be retired for the following reasons:
These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Provider (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

FAC-013-2 Requirements R1, R2, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Assessing transfer capability above the “known commitments for Firm Transmission Service and Interchange” required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as TP, do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable system performance is.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.
- Requirement R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.

Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by FERC in 2014.

INT-004-3.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
INT-004-3.1 may be retired since it satisfies Paragraph 81 Criteria ‘B6 – Commercial or Business Practice.’ Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity, has been removed from the list of NERC Functional Entities, supporting the

market-based observations herein. Requirement R3 specifically refers to "Pseudo-Ties that are included in the NAESB Electric Industry Registry," reinforcing the tie to North American Energy Standards Board (NAESB) Wholesale Electric Quadrant (WEQ) Business Practice Standards.

INT-006-4, Requirements R3.1, R4, and R5
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these requirements should be retired for the following reasons:
INT-006-4, Requirement R3 Part 3.1 can be retired under Paragraph 81, Criterion A. There is no substantive impact on reliability with requiring the RC to be notified when a Reliability Adjustment Arranged Interchange has been denied.

INT-006-4, Requirement R4 can be retired under Paragraph 81, Criteria A and B7. Covered in North American Energy Standards Board (NAESB) e-Tagging specifications, Section 1.6.3.1 and Section 1.3, Request State. This requirement outlines the conditions that must exist for an Arranged Interchange to transition to Confirmed Interchange. NAESB Electronic Tagging Specification Section 1.6.3.1 and Section 1.3, Request State, stipulate these exact requirements. INT-006-4, Requirement R4 is being recommended for retirement, the requirement is accomplished through a Balancing Authority's (BA) e-Tag Authority Service and does not have an impact on reliability.

INT-006-4, Requirement R5 can be retired under Paragraph 81, Criteria A and B7. This is covered in NAESB e-Tagging specifications, Section 1.6.4. This requirement outlines who is notified when the transition to Confirmed Interchange occurs. NAESB Electronic Tagging Specification, Section 1.6.4, stipulate these exact requirements. INT-006-4, Requirement R5 is being recommended for retirement, the requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-009-2.1, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this requirement should be retired for the following reasons: This requirement can be retired under Paragraph 81, Criterion B7, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7.

INT-010-2.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
The opportunity exists to retire Reliability Standard INT-010-2.1 in its entirety. INT-010-2.1, Requirement R1: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-1. Therefore, this requirement is

duplicative and does little, if anything, to benefit or protect the reliable operation of the Bulk Electric System (BES).

INT-010-2.1, Requirement R2: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended for retirement. More stringent tagging requirements already exist in NAESB WEQ 004-8. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R3: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommendation for retirement. More stringent tagging requirements already exist in NAESB WEQ 004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5, Requirements R1, R4 and R6:
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R1, Retain Requirements R4 and R6
<u>Rationale</u>
The SDT believes that Requirement R1 should be retired for the following reasons:
Requirement R1 of IRO-002-5 is redundant to other requirements in the IRO family of standards. The requirement is a control for aiding compliance with IRO-008-2, Requirement R1 related to the performance of an Operational Planning Analysis (OPA), and it is duplicative to Requirement R3 in IRO-010-2. The purpose of IRO-010-2 is to ensure adequate data is collected so that reliability is not adversely impacted by preventing instability, uncontrolled separation, or Cascading outages and is applicable to all functional entities in the RC area. The purpose of IRO-008-2 is for the RC to perform the analysis to prevent instability, uncontrolled separation, or Cascading and with the data collected per IRO-010-2. The data exchange capabilities are indicated in IRO-010-2, Requirement R3, which includes BAs and TOPs, and IRO-008-2, Requirement R1 requires the RC to perform the OPA, which makes IRO-002-5, Requirement R1 redundant with the aforementioned standards and requirements.

IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to comply with IRO-010-2, Requirement R3, it must be able to exchange data with the requesting RC. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the OPA. Finally, Measure M1 for IRO-002-5, Requirement R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the IRO-002-5, Requirement R1 is not needed to support reliability and can be retired.

The SDT believes that Requirements R4 and R6 should be retained for the following reasons:
IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

Requirement R4 of IRO-002-5 needs to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), Internet Technology (IT), or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (cf. IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. In addition, RC equipment outages are not required to follow the RC's outage coordination process (i.e., IRO-017-1, Requirement R2 is only applicable to TOPs and BAs). As such, a potential gap in the standards would exist if IRO-002-5, Requirement R4 was retired.

IRO-008-2, Requirement R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
Although IRO-008-2, Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6 is not being sought during this phase of the project.

IRO-014-3, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (Requirement R1, Part 1.1), this ensures RC operations are coordinated to maintain reliability of the BES. As such, a separate requirement for ensuring notifications are made to impacted RCs is duplicative. However, IRO-014-3, Requirement R1 time horizon would need to be revised to a time horizon of "Real-time" if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3 is not being sought during this phase of the project.

SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R3 of IRO-014-3 to determine if there is opportunity for revision to IRO-014-3, Requirement R1 that would satisfy the revision of the time horizon to "Real-time." If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R3 of IRO-014-3 may be able to be looked at for retirement within that project or within a future project.

IRO-017-1, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3 for retirement.
SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TLP-001-4 that would satisfy the adding the RC as a named recipient. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R3 of IRO-017-1 may be able to be looked at for retirement within that project or within a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3, MOD-001-1a and proposed MOD-001-2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these standards should be retired for the following reasons:
Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-020-0, Requirement R1 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
MOD-031-2 and IRO-010-2 do give the necessary entities the authority to request relevant information nor does MOD-031-2 and IRO-010-2 require the associated entities to provide that information. Demand-Side Management (DSM) data is necessarily related to the near-term operating time horizon, as well as the planning time horizons, but not to the Real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4, Requirements R1 and R2, and IRO-001-4, Requirement R1, the RC,

BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over DSM. They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4, Requirement R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0 R1 are sources of DADS data, have access to DADS data, or both.

DSM and Direct Control Load Management (DLCM) may be regarded as long-term-planning and operations-planning time horizon resources, but, particularly with a “on request within 30 calendar days” obligation in the requirement, is not a resource for the Real-time or day-ahead operating time horizon for Reliability Coordinators and Transmission Operators, which must plan to operate, and actually operate, the BES within SOLs and IROLs, a subset of SOLs. In addition, the amount of interruptible demands and DLCM at the TP, Resource Planner (RP), and/or Load-Serving Entity (LSE) (which has been removed from the compliance registry and is no longer obligated to comply with NERC standards) level is not of locational benefit to TOPs and RCs to assist them in operating within SOLs, as such information, were it to be provided within a usable time frame, would not be sufficiently granular to assist the TOP and RC. All meaningful information regarding interruptible demands and DLCM is available from DADS, which, in the United States, is a mandatory reporting mechanism, regulated per Section 1600 of the NERC Rules of Procedure. DSM and DLCM are financially-enabled mechanisms whereupon RPs may encourage customers and customer groups to permit local control of their load in exchange for rate considerations. And this local control may or may not be sited in such a manner to provide any benefit to TOPs and RCs; which, again, are obligated by NERC Standards to operate the BES within SOLs.

PRC-004-5(i), Requirement R4
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this requirement should be retired for the following reasons:
The standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for BES Elements. The Reliability Standard's Guideline and Technical Basis for Requirement R4 considers due diligence that an entity must make in determining the cause of a Protection System Misoperation.

The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with Requirements R1 and R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a Misoperation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity’s internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation, and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of Requirement R4 does not preclude the entity’s responsibility to continue the investigation to identify the cause of Misoperation. However, it does alleviate the need to keep tracking documents for the sake of showing investigative actions.

PRC-015-1 Requirements R1, R2, and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this standard should be retained for the following reasons:
PRC-015-1 is scheduled to be retired on 12/31/2020 under the PRC-012-2 Implementation Plan (IP).

PRC-018-1 Requirements R1, R2, R3, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this standard should be retained for the following reasons:
PRC-018-1 is superseded by PRC-002-2 in Year 2022. The PRC-002-2 IP states: "Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2…"

TOP-001-4 Requirements R16, R17, R19 and R22
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain Requirements R16 and R17, Retire Requirements R19 and R22
Rationale
The SDT believes Requirements R16 and R17 should be retained for the following reasons:
Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

The Purpose of TOP-003-3 is to ensure adequate data is collected by the BA and TOP to fulfill their operational and planning responsibilities. The Purpose of TOP-002-4 is to ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22 for the BA and TOP are redundant with TOP-003-3, Requirements R3, R4 and R5 and TOP-002-4, Requirement R1.

The SDT believes Requirements R19 and R22 should be retired for the following reasons:
TOP-001-4, Requirement R19 is redundant to other requirements in the TOP family of standards. For TOPs, the existing TOP-003-3, Requirement R5 cannot be fulfilled by entities unless data exchange capabilities exist between the TOP and the supplying entities. Similarly, TOP-002-4, Requirement R1

cannot be fulfilled by the TOP unless the data needed to perform the OPA has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R19 in TOP-001-4 is not needed to support reliability and can be retired.

TOP-001-4, Requirement R22 is redundant to other requirements in the TOP family of standards. For the BA, the existing TOP-003-3, Requirement R5 cannot be fulfilled by entities unless data exchange capabilities exist between the BA and the supplying entities. Similarly, TOP-002-4, Requirement R4 cannot be fulfilled by the BA unless the data needed to develop its Operating Plan for next-day operations has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R22 in TOP-001-4 is not needed to support reliability and can be retired.

VAR-001-5*, Requirements R2 and R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R2, Retain Requirement R3
Rationale
The SDT believes Requirement R2 should be retired for the following reasons:
VAR-001-5, Requirement R2 is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

TOP-002-4, Requirement R1 thus requires the TOP to have an OPA that assess whether its next-day planned operations will exceed any SOLs, and TOP-001-4, Requirement R10 thus requires that the TOP monitor its Facilities and thus determine SOL exceedances. Further, TOP-001-4, Requirement R14 requires that the TOP "…initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment…" and TOP-001-4, Requirement R1 requires that the TOP "…shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions."

Since operating outside voltage limits represents a SOL exceedance, the TOP must have an OPA that assesses whether its next-day operations will exceed SOLs. The TOP has the obligation to initiate an Operating Plan to mitigate an SOL exceedance, and has the responsibility to take any actions under its control and issue Operating Instructions, if needed. The responsibilities elucidated in VAR-001-4.1, Requirement R2 are fully addressed in these other standards; scheduling sufficient reactive resources to regulate voltage levels under normal and Contingency conditions is one of several vital elements of addressing this obligation.

The SDT believes Requirement R3 should be retained for the following reasons:
For reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL to prevent voltage-collapse events wherein the operation within SOLs/IROLs itself is not adequate to assure stable voltage operations in both steady-state and transient conditions. The TOP-series of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary.

* VAR-001-4.2, is an inactive standard. VAR-001-5 changed the WECC variance, and not the continent-wide requirements. VAR-001-5 became effective January 1, 2019.

Standards Announcement

Project 2018-03 Standards Efficiency Review Retirements

45-day Formal Comment Period Open through April 12, 2019
Ballot Pools Forming through March 28, 2019

Now Available

A 45-day comment period is open for the **Project 2018-03 Standards Efficiency Review Retirements** until **8 p.m. Eastern, Friday, April 12, 2019**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues using the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, March 28, 2019.** Registered Ballot Body members can join the ballot pools here. Note that there is a separate ballot for each of the standards, so it is necessary to join multiple pools in order to submit votes on the standards.

- *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).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

A 10-day initial ballot for the standards (proposed for partial retirement) and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels, as well as ballots for the standards proposed for complete retirement and a standard proposed for withdrawal, will be conducted **April 3-12, 2019.**

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2018-03 Standards Efficiency Review Retirements

45-day Formal Comment Period Open through April 12, 2019
Ballot Pools Forming through March 28, 2019

Now Available

A 45-day comment period is open for the **Project 2018-03 Standards Efficiency Review Retirements** until **8 p.m. Eastern, Friday, April 12, 2019**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues using the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, March 28, 2019.** Registered Ballot Body members can join the ballot pools here. Note that there is a separate ballot for each of the standards, so it is necessary to join multiple pools in order to submit votes on the standards.

- *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).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

A 10-day initial ballot for the standards (proposed for partial retirement) and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels, as well as ballots for the standards proposed for complete retirement and a standard proposed for withdrawal, will be conducted **April 3-12, 2019.**

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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

Standards Announcement

Project 2018-03 Standards Efficiency Review Retirements

Initial Ballots and Non-ballot Polls Open through April 12, 2019

Now Available

The initial ballots and non-binding polls for the **Project 2018-03 Standards Efficiency Review Retirements** are open until **8 p.m. Eastern, Friday, April 12, 2019.**

Balloting

Members of the ballot pools associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit their votes. If you experience issues using the 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).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements FAC-008-4 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 275
Total Ballot Pool: 317
Quorum: 86.75
Quorum Established Date: 4/12/2019 2:00:59 PM
Weighted Segment Value: 96.18

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	85	1	67	0.985	1	0.015	0	5	12
Segment: 2	8	0.7	6	0.6	1	0.1	0	1	0
Segment: 3	71	1	57	0.983	1	0.017	0	3	10
Segment: 4	15	1	12	1	0	0	0	0	3
Segment: 5	74	1	61	0.984	1	0.016	0	1	11
Segment: 6	54	1	48	1	0	0	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	317	6.5	258	6.252	5	0.248	0	12	42

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	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		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
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		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham	Joseph Amato	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Abstain	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
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.	Dmitriy Bazylyuk		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Negative	Third-Party Comments
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		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		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		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 317 of 317 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements FAC-013-2 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 263
Total Ballot Pool: 299
Quorum: 87.96
Quorum Established Date: 4/12/2019 2:03:44 PM
Weighted Segment Value: 98.88

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	79	1	61	0.984	1	0.016	0	6	11
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	53	0.981	1	0.019	0	5	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	68	1	57	0.983	1	0.017	0	2	8
Segment: 6	53	1	44	0.978	1	0.022	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	299	6.6	243	6.526	4	0.074	0	16	36

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	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.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 299 of 299 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-004-3.1 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 259
Total Ballot Pool: 295
Quorum: 87.8
Quorum Established Date: 4/12/2019 2:03:56 PM
Weighted Segment Value: 97.41

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	76	1	59	0.967	2	0.033	0	4	11
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	52	0.963	2	0.037	0	4	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	68	1	56	0.966	2	0.034	0	2	8
Segment: 6	53	1	42	0.933	3	0.067	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	295	6.6	237	6.429	9	0.171	0	13	36

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	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	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
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	Christopher Overberg		Affirmative	N/A
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	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 295 of 295 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-006-5 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 298
Quorum: 87.58
Quorum Established Date: 4/12/2019 1:55:40 PM
Weighted Segment Value: 97.79

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	77	1	58	0.951	3	0.049	0	5	11
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	52	0.963	2	0.037	0	4	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	69	1	57	0.983	1	0.017	0	2	9
Segment: 6	53	1	43	0.956	2	0.044	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	298	6.7	239	6.552	8	0.148	0	14	37

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		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	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	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	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		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	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 298 of 298 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-009-3 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 298
Quorum: 87.58
Quorum Established Date: 4/12/2019 1:55:54 PM
Weighted Segment Value: 98.51

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	77	1	61	1	0	0	0	5	11
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	54	1	0	0	0	4	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	69	1	58	1	0	0	0	2	9
Segment: 6	53	1	45	1	0	0	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	298	6.7	246	6.6	1	0.1	0	14	37

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		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	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-010-2.1 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 259
Total Ballot Pool: 296
Quorum: 87.5
Quorum Established Date: 4/12/2019 2:04:12 PM
Weighted Segment Value: 89.75

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	76	1	57	0.934	4	0.066	0	4	11
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	50	0.926	4	0.074	0	4	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	69	1	53	0.93	4	0.07	0	3	9
Segment: 6	53	1	42	0.933	3	0.067	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	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: 9	1	0.1	0	0	1	0.1	0	0	0
Segment: 10	6	0.5	4	0.4	1	0.1	0	1	0
Totals:	296	6.6	226	5.924	19	0.676	0	14	37

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	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	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		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	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	Third-Party Comments
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		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements IRO-002-6 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 298
Quorum: 87.58
Quorum Established Date: 4/12/2019 2:29:10 PM
Weighted Segment Value: 98.53

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	78	1	59	1	0	0	0	8	11
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	51	1	0	0	0	7	10
Segment: 4	13	1	11	1	0	0	0	1	1
Segment: 5	68	1	56	1	0	0	0	3	9
Segment: 6	53	1	43	1	0	0	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	298	6.8	237	6.7	1	0.1	0	23	37

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Abstain	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		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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 Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		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		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-001-1a IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 269
Total Ballot Pool: 308
Quorum: 87.34
Quorum Established Date: 4/12/2019 2:04:26 PM
Weighted Segment Value: 96.6

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	83	1	65	0.956	3	0.044	0	3	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	55	0.948	3	0.052	0	2	10
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	71	1	58	0.935	4	0.065	0	0	9
Segment: 6	53	1	44	0.936	3	0.064	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	308	6.6	250	6.376	13	0.224	0	6	39

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	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.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 308 of 308 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-001-2 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 303
Quorum: 87.46
Quorum Established Date: 4/12/2019 2:06:20 PM
Weighted Segment Value: 95.96

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	82	1	64	0.955	3	0.045	0	3	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	53	0.93	4	0.07	0	2	10
Segment: 4	13	1	12	1	0	0	0	0	1
Segment: 5	69	1	56	0.933	4	0.067	0	0	9
Segment: 6	53	1	43	0.915	4	0.085	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	303	6.6	244	6.333	15	0.267	0	6	38

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 303 of 303 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-004-1 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 268
Total Ballot Pool: 310
Quorum: 86.45
Quorum Established Date: 4/12/2019 2:19:47 PM
Weighted Segment Value: 96.6

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	82	1	64	0.955	3	0.045	0	3	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	55	0.948	3	0.052	0	2	10
Segment: 4	16	1	12	1	0	0	0	0	4
Segment: 5	71	1	57	0.934	4	0.066	0	0	10
Segment: 6	54	1	45	0.938	3	0.063	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	310	6.6	249	6.375	13	0.225	0	6	42

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co	Marcus Moor	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 310 of 310 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-008-1 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 269
Total Ballot Pool: 308
Quorum: 87.34
Quorum Established Date: 4/12/2019 2:05:13 PM
Weighted Segment Value: 95.8

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	83	1	64	0.941	4	0.059	0	3	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	54	0.931	4	0.069	0	2	10
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	71	1	58	0.935	4	0.065	0	0	9
Segment: 6	53	1	43	0.915	4	0.085	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	308	6.6	247	6.323	16	0.277	0	6	39

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	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.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 308 of 308 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-020-0 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 269
Total Ballot Pool: 310
Quorum: 86.77
Quorum Established Date: 4/12/2019 2:14:07 PM
Weighted Segment Value: 98.95

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	83	1	66	0.985	1	0.015	0	4	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	56	0.982	1	0.018	0	2	10
Segment: 4	15	1	12	1	0	0	0	0	3
Segment: 5	72	1	61	0.984	1	0.016	0	0	10
Segment: 6	54	1	47	0.979	1	0.021	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	310	6.6	258	6.531	4	0.069	0	7	41

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 310 of 310 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-028-2 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 304
Quorum: 87.17
Quorum Established Date: 4/12/2019 2:13:13 PM
Weighted Segment Value: 96.45

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	81	1	62	0.954	3	0.046	0	4	12
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	70	1	55	0.948	3	0.052	0	2	10
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	70	1	57	0.934	4	0.066	0	0	9
Segment: 6	53	1	44	0.936	3	0.064	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	304	6.4	244	6.173	13	0.227	0	8	39

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		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		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 304 of 304 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-029-2a IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 304
Quorum: 87.17
Quorum Established Date: 4/12/2019 2:13:16 PM
Weighted Segment Value: 96.54

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	81	1	62	0.954	3	0.046	0	4	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	54	0.947	3	0.053	0	2	10
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	70	1	57	0.934	4	0.066	0	0	9
Segment: 6	53	1	44	0.936	3	0.064	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	304	6.6	245	6.372	13	0.228	0	7	39

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		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		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	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	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 304 of 304 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-030-3 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 305
Quorum: 86.89
Quorum Established Date: 4/12/2019 2:13:58 PM
Weighted Segment Value: 95.9

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	82	1	64	0.955	3	0.045	0	3	12
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	69	1	53	0.93	4	0.07	0	2	10
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	70	1	56	0.933	4	0.067	0	0	10
Segment: 6	53	1	43	0.915	4	0.085	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	305	6.5	243	6.233	15	0.267	0	7	40

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 305 of 305 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements PRC-004-6 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 276
Total Ballot Pool: 322
Quorum: 85.71
Quorum Established Date: 4/12/2019 2:19:42 PM
Weighted Segment Value: 88.42

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	85	1	65	0.929	5	0.071	0	3	12
Segment: 2	8	0.7	6	0.6	1	0.1	0	1	0
Segment: 3	72	1	56	0.933	4	0.067	0	2	10
Segment: 4	18	1	12	1	0	0	0	0	6
Segment: 5	75	1	59	0.937	4	0.063	0	0	12
Segment: 6	54	1	45	0.938	3	0.063	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	3	0.3	3	0.3	0	1	0
Totals:	322	6.6	248	5.836	21	0.764	0	7	46

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Third-Party Comments
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	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		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
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		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	Third-Party Comments
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Rutherford EMC	Tom Haire		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Negative	Third-Party Comments
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Third-Party Comments
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 322 of 322 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements TOP-001-5 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 275
Total Ballot Pool: 321
Quorum: 85.67
Quorum Established Date: 4/12/2019 2:29:27 PM
Weighted Segment Value: 98.96

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	85	1	68	0.986	1	0.014	0	4	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	74	1	58	0.983	1	0.017	0	3	12
Segment: 4	16	1	12	1	0	0	0	0	4
Segment: 5	75	1	62	0.984	1	0.016	0	0	12
Segment: 6	53	1	46	0.979	1	0.021	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	0	2	0
Totals:	321	6.6	262	6.531	4	0.069	0	9	46

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
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		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
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		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Sharon Flannery		None	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 321 of 321 entries

Previous 1 Next

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/165)
Ballot Name: 2018-03 Standards Efficiency Review Retirements VAR-001-6 IN 1 ST
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 273
Total Ballot Pool: 316
Quorum: 86.39
Quorum Established Date: 4/12/2019 2:14:57 PM
Weighted Segment Value: 97.69

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	85	1	66	0.957	3	0.043	0	4	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	71	1	56	0.966	2	0.034	0	2	11
Segment: 4	14	1	12	1	0	0	0	0	2
Segment: 5	75	1	61	0.968	2	0.032	0	0	12
Segment: 6	53	1	45	0.957	2	0.043	0	0	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	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: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	0	2	0
Totals:	316	6.6	256	6.448	9	0.152	0	8	43

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A

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		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	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.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	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	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 316 of 316 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements FAC-008-4 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 249
Total Ballot Pool: 295
Quorum: 84.41
Quorum Established Date: 4/12/2019 2:57:59 PM
Weighted Segment Value: 98.11

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	51	0.981	1	0.019	14	11
Segment: 2	7	0.5	5	0.5	0	0	1	1
Segment: 3	68	1	47	0.979	1	0.021	9	11
Segment: 4	14	1	11	1	0	0	1	2
Segment: 5	70	1	51	0.981	1	0.019	5	13
Segment: 6	50	1	37	1	0	0	5	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.5	4	0.4	1	0.1	1	0
Totals:	295	6.2	208	6.041	4	0.159	37	46

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham	Joseph Amato	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Abstain	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	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	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 295 of 295 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-006-5 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 236
Total Ballot Pool: 279
Quorum: 84.59
Quorum Established Date: 4/12/2019 2:56:23 PM
Weighted Segment Value: 97.5

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	70	1	46	0.958	2	0.042	12	10
Segment: 2	7	0.5	5	0.5	0	0	1	1
Segment: 3	65	1	43	0.977	1	0.023	9	12
Segment: 4	13	1	11	1	0	0	1	1
Segment: 5	65	1	47	0.979	1	0.021	6	11
Segment: 6	50	1	35	0.972	1	0.028	6	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	279	6.3	195	6.187	5	0.113	36	43

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		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	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 279 of 279 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-009-3 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 236
Total Ballot Pool: 279
Quorum: 84.59
Quorum Established Date: 4/12/2019 2:56:27 PM
Weighted Segment Value: 99

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	70	1	47	0.979	1	0.021	12	10
Segment: 2	7	0.5	4	0.4	1	0.1	1	1
Segment: 3	65	1	44	1	0	0	9	12
Segment: 4	13	1	11	1	0	0	1	1
Segment: 5	65	1	48	1	0	0	6	11
Segment: 6	50	1	36	1	0	0	6	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	279	6.3	198	6.179	2	0.121	36	43

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	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	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 279 of 279 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements IRO-002-6 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 235
Total Ballot Pool: 279
Quorum: 84.23
Quorum Established Date: 4/12/2019 3:21:18 PM
Weighted Segment Value: 99.47

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	44	0.978	1	0.022	16	11
Segment: 2	7	0.5	5	0.5	0	0	1	1
Segment: 3	65	1	42	1	0	0	11	12
Segment: 4	13	1	10	1	0	0	2	1
Segment: 5	63	1	45	1	0	0	7	11
Segment: 6	50	1	34	1	0	0	8	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	279	6.3	188	6.278	1	0.022	46	44

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Vivian Vo		Abstain	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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 279 of 279 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements PRC-004-6 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 298
Quorum: 82.89
Quorum Established Date: 4/12/2019 3:11:36 PM
Weighted Segment Value: 92.06

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	50	0.909	5	0.091	11	11
Segment: 2	7	0.5	4	0.4	1	0.1	1	1
Segment: 3	68	1	43	0.915	4	0.085	8	13
Segment: 4	16	1	11	1	0	0	1	4
Segment: 5	71	1	50	0.962	2	0.038	5	14
Segment: 6	50	1	34	0.944	2	0.056	6	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.6	3	0.3	3	0.3	0	0
Totals:	298	6.3	197	5.63	17	0.67	33	51

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	Comments Submitted
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	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	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements TOP-001-5 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 295
Quorum: 83.39
Quorum Established Date: 4/12/2019 3:02:52 PM
Weighted Segment Value: 97.66

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	53	0.964	2	0.036	11	11
Segment: 2	7	0.6	6	0.6	0	0	0	1
Segment: 3	69	1	46	0.979	1	0.021	8	14
Segment: 4	14	1	11	1	0	0	1	2
Segment: 5	69	1	50	0.98	1	0.02	5	13
Segment: 6	50	1	36	0.973	1	0.027	5	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.4	4	0.4	0	0	2	0
Totals:	295	6.3	209	6.196	5	0.104	32	49

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	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	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	None	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 295 of 295 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements VAR-001-6 Non-binding Poll IN 1 NB
Voting Start Date: 4/3/2019 12:01:00 AM
Voting End Date: 4/12/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 295
Quorum: 83.73
Quorum Established Date: 4/12/2019 3:01:07 PM
Weighted Segment Value: 95.77

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	52	0.945	3	0.055	11	11
Segment: 2	7	0.4	4	0.4	0	0	2	1
Segment: 3	68	1	45	0.957	2	0.043	8	13
Segment: 4	13	1	11	1	0	0	1	1
Segment: 5	71	1	50	0.962	2	0.038	5	14
Segment: 6	50	1	35	0.946	2	0.054	5	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.4	4	0.4	0	0	2	0
Totals:	295	6.1	204	5.91	9	0.19	34	48

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		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	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Abstain	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		None	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	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		None	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Comment Report

Project Name:	2018-03 Standards Efficiency Review Retirements
Comment Period Start Date:	2/27/2019
Comment Period End Date:	4/12/2019
Associated Ballots:	2018-03 Standards Efficiency Review Retirements FAC-008-4 IN 1 ST 2018-03 Standards Efficiency Review Retirements FAC-013-2 IN 1 ST 2018-03 Standards Efficiency Review Retirements INT-004-3.1 IN 1 ST 2018-03 Standards Efficiency Review Retirements INT-006-5 IN 1 ST 2018-03 Standards Efficiency Review Retirements INT-009-3 IN 1 ST 2018-03 Standards Efficiency Review Retirements INT-010-2.1 IN 1 ST 2018-03 Standards Efficiency Review Retirements IRO-002-6 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-001-1a IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-001-2 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-004-1 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-008-1 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-020-0 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-028-2 IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-029-2a IN 1 ST 2018-03 Standards Efficiency Review Retirements MOD-030-3 IN 1 ST 2018-03 Standards Efficiency Review Retirements PRC-004-6 IN 1 ST 2018-03 Standards Efficiency Review Retirements TOP-001-5 IN 1 ST 2018-03 Standards Efficiency Review Retirements VAR-001-6 IN 1 ST

There were 49 sets of responses, including comments from approximately 119 different people from approximately 81 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include: BAL-005-1, Requirements R4 and R6; COM-002-4, Requirement R2; EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; IRO-014-3, Requirement R3; IRO-017-1, Requirement R3; and VAR-001-5, Requirement R3. Do you agree with the SDT's recommendation that these standards requirements be considered as part of the SER Phase II effort? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

2. The SDT is proposing to take no action on two standards already scheduled for retirement: PRC-015-1, Requirements R1, R2 and R3; and PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6. Do you agree with the SDT's recommendation to take no action for these standards already scheduled for retirement? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

3. The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit: IRO-002-5, Requirements R4 and R6; IRO-008-2, Requirement R6, and TOP-001-4, Requirements R16 and R17. Do you agree with the SDT's recommendation to retain these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

4. The SDT is proposing to retire FAC-008-3, Requirements R7 and R8. Do you agree with the SDT's proposal to retire these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

5. The SDT is proposing to retire FAC-013-2, Requirements R1, R2, R4, R5 and R6 (all). Do you agree with the SDT's proposal to retire FAC-013-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

6. The SDT is proposing to retire INT-004-3.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-004-3.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

7. The SDT is proposing to retire INT-006-4, Requirements R3.1, R4, and R5. Do you agree with the SDT's proposal to retire Requirements R3.1, R4, and R5 of INT-006-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

8. The SDT is proposing to retire INT-009-2.1, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of INT-009-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

9. The SDT is proposing to retire INT-010-2.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-010-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

10. The SDT is proposing to retire IRO-002-5, Requirement R1. Do you agree with the SDT's proposal to retire Requirement R1 of IRO-002-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

12. The SDT is proposing to retire MOD-008-1, Requirements R1, R2, R3, R4, and R5 (all). Do you agree with the SDT's proposal to retire MOD-008-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

13. The SDT is proposing to retire MOD-028-2, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, and R11 (all). Do you agree with the SDT's proposal to retire MOD-028-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

14. The SDT is proposing to retire MOD-029-2a, Requirements R1, R2, R3, R4, R5, R6, R7, and R8 (all). Do you agree with the SDT's proposal to retire MOD-029-2a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

15. The SDT is proposing to retire MOD-030-3, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9 and R10 (all). Do you agree with the SDT's proposal to retire MOD-030-3? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

16. The SDT is proposing to retire MOD-001-1a, Requirements R1, R2, R3, R4, R5, R6, R7, R8 and R9 (all). Do you agree with the SDT's proposal to retire MOD-001-1a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

17. The SDT is proposing to withdraw Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities. Do you agree with the SDT's proposal to withdraw Reliability Standard MOD-001-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

18. The SDT is proposing to retire MOD-020-0, Requirement R1 (all). Do you agree with the SDT's proposal to retire MOD-020-0? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

19. The SDT is proposing to retire PRC-004-5(i), Requirement R4. Do you agree with the SDT's proposal to retire Requirement R4 of PRC-004-5(i)? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

20. The SDT is proposing to retire TOP-001-4, Requirements R19 and R22. Do you agree with the SDT's proposal to retire Requirements R19 and R22 of TOP-001-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

21. The SDT is proposing to retire VAR-001-5, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of VAR-001-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

22. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	Tennessee Valley Authority	Kurtz, Bryan G.	Tennessee Valley Authority	1	SERC
					Grant, Ian S.	Tennessee Valley Authority	3	SERC
					Thomas, M. Lee	Tennessee Valley Authority	5	SERC
					Parsons, Marjorie S.	Tennessee Valley Authority	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC,WECC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Kagen DelRio	North Carolina Electric Membership Cooperative	3,4,5	SERC
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	SERC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC

					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion, Con-Edison	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick	Kowalczyk	1	NPCC
					John Hastings	National Grid	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include: BAL-005-1, Requirements R4 and R6; COM-002-4, Requirement R2; EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; IRO-014-3, Requirement R3; IRO-017-1, Requirement R3; and VAR-001-5, Requirement R3. Do you agree with the SDT's recommendation that these standards requirements be considered as part of the SER Phase II effort? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

- BAL-005-1 R4 & R6 are now adequately covered under TOP-010-1(i) and are redundant to list under BAL-005-1
- COM-002-4 R2 should be covered in each entities Systematic Approach to Training per PER-005-2.
- EOP-005-3 R8 should be covered in each entities Systematic Approach to Training per PER-005-2.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment

GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.

Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	

Comment

IID believes these requirements the SDT has recommended to be considered as part of the SER Phase II effort should proceed to ballot as proposed retirements based on the original SAR and recommendations from the SER Phase I teams. This would allow the Registered Ballot Body to vote on whether these requirements are appropriate for retirement or if additional work is necessary. If the retirement of these requirements do not pass ballot, IID supports that they be considered as part of SER Phase II, however the SDT should ensure the SER Phase II scope clearly indicates they will address requirements. Note that the current SER Phase II scope and six efficiency concepts does not indicate they will be addressing specific requirements.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Regarding BAL-005-1 req.4, Southern Company believes that in order for the BA operators to be able to perform their job effectively, then the BA manager must provide the adequate tools needed that are associated with Reporting ACE. To ensure that the information is correct, the BA manager must ensure that operators have accurate information and have indicators if data is either missing or incorrect. Having the current standard only places an administrative burden on BA entities who already have the tools in place and are training their operators on Reporting ACE. Therefore, retiring this requirement would not leave a gap in reliability.

In regard to BAL-005-1 req, 6, this is another requirement that poses an administrative burden on BA entities as the calculation of Reporting ACE is critical for any entity to effectively balance load/generation and support interconnection frequency. Again, this is an inherent function of BA entities and retiring this requirement would not leave a gap in reliability.

In regard to COM-002-4 req. 2, Southern believes that this requirement could easily be incorporated the current PER-005 standard as it involves System Operator training.   Even if the requirement was retired without including it anywhere else in the NERC standards, COM-002-4 R1 would still be enforceable and would require System Operators to follow the documented communication protocols. We don't believe that any additional work is necessary by the SDT as the retirement of this standard would not result in a reliability gap.

The related compliance activities in EOP-005-3 R8 can easily be incorporated into the PER-005 standards as a part of an entity's Systematic Approach to Training. System restoration is a reliability-related task and should be included in an entity's training program for its System Operators to ensure that they are and competent to perform restoration activities.

The related compliance activities in EOP-006-3 R7 can easily be incorporated into the PER-005 standards as a part of an entity's Systematic Approach to Training. System restoration is a reliability-related task and should be included in an entity's training program for its System Operators to ensure that they are and competent to perform restoration activities.

In regard to IRO-014-3 req. 3, this is an inherent part of performing as a Reliability Coordinator as coordination is at the heart of this function. A standard requirement is not needed, because the RC serves an area and has responsibilities for multiple entities. Any improprieties by the RC, will surely be voiced by one or more of the member entities and therefore, a requirement is not needed, and therefore we don't believe that any additional work is necessary by the SDT before retiring this requirement.

In regard to VAL-001-5 R3, Monitoring and maintaining voltage/regulating devices is an inherent responsibility of the TOP entity. It is also essential in ensuring effective operations to effectively transfer power while minimizing losses. Furthermore, it is in the TOP entity's best interest to maintain system voltage to avoid overloading the system and causing SOLs and IROLs, along with damage to transmission equipment and facilities. Since these

functions are done inherently, the NERC standard only increases the administrative burden on the entities and therefore, retirement of this requirement would not create a gap in reliability.	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
In consideration that the actions specified in VAR-001-5 R3 are inherent to the System Operators' core functions, LES believes R3 is still suitable for retirement as part of the SER Phase I effort. The prevention and mitigation of SOL exceedances, as dictated by applicable TOP standards, ensures System Operators utilize the necessary devices to regulate transmission voltage and reactive flow. This requirement provides no additional direction and taken independently is too vague to provide useful guidance in ensuring reliability.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
If EOP-005-3 R8 is retired, R9 and R10 should be considered at the same time with potential migration into the PER Standards. If EOP-006-3 R7 is retired, R8 should be considered at the same time with potential migration into the PER Standards. Please note that EOP-005-3 and EOP-006-3 are enforceable 04/01/19. If IRO-017-1 R3 is to be retired, A new TPL-001-5 R8 should include the RC function.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
SRP supports the retirement of the requirements above in the SER Phase II effort.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the justification for retaining COM-002-4 Requirement R2 and EOP-005-3 Requirement R8.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	

LDWP agrees that IRO-017-1 should be a part of a Phase II effort. If the TPL-001-4 standard is not clarified to notify Peak RC of the transmission results then there may not be a mechanism for notifying the RC about potential IROLs.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	Yes
Document Name	

Comment

Although we agree with moving these Requirements into the SER Phase II effort, there is a concern that addressing these Requirements may be delayed due to the Phase II 'Concept' selection process. Currently the Phase II Concept process has a timeline that extends into September and that date is only for deciding which recommendation(s) to use.

Also, there is no assurance that the Concepts chosen in Phase II will address the deferred Requirements proposed for retirement in Phase I.

A suggestion would be for the Phase II team to address these deferred Requirements separately as they decide on which Concepts to use.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas

City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support Edison Electric Institute's response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that some Reliability Standards and associated requirements present more complex consideration and research in order to ensure proposed retirements do not create unintended reliability gaps. Moreover, we support the proposal to shift such requirements to the SER Phase II effort. However, the recent posting on the SER Phase II Concepts has created some confusion. EEI recommends that NERC or the SER Advisory provide additional information to help clarify the full scope of the upcoming SER Phase II Project—including these requirements for consideration for Phase II and the proposed Concepts. EEI also encourages the SDT to prioritize these requirements for Phase II so that progress is not held up by the SDT efforts to refine the proposed Concepts.	
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

If EOP-005-3 R8 is retired, R9 and R10 should be considered at the same time with potential migration into the PER Standards.

If EOP-006-3 R7 is retired, R8 should be considered at the same time with potential migration into the PER Standards.

Please note that EOP-005-3 and EOP-006-3 are enforceable 04/01/19.

If IRO-017-1 R3 is to be retired, A new TPL-001-5 R8 should include the RC function.

Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	

Comment

In conducting the review, we suggest that where requirements are found to be somewhat, but not completely duplicative, consider proceeding with the retirement of the identified requirements and adding any language of the retired requirement that is still pertinent to the requirements which will still be in effect.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

It appears from the technical rational document that the 2018-03 drafting team believes the Requirements should be revised and retained rather than retired in their entirety. Since standard revision is within the scope of the Phase 2 team, AEP has no objections to the concept of revising COM-002-4 R2, EOP-005-3 R8, IRO-017-1 R3, and VAR-001-5 R3.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kelsi Rigby - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
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

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

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

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
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	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	

2. The SDT is proposing to take no action on two standards already scheduled for retirement: PRC-015-1, Requirements R1, R2 and R3; and PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6. Do you agree with the SDT's recommendation to take no action for these standards already scheduled for retirement? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
PRC-018-1 references Regional Criteria that must be followed to comply with the standard. Duke Energy requests the drafting team consider the ramifications on PRC-018-1 if a Region has already retired its Regional Criteria applicable to PRC-018 and PRC-002. The absence of any applicable Regional Criteria for a particular Region, makes PRC-018-1 a stronger candidate for immediate retirement.	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OKGE disagrees with the SDT's proposal of taking no action on PRC-018-1. Per the PRC-002-2 Implementation Plan,	

“Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity’s Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.”

OKGE believes this justification is flawed. The requirements in PRC-018-1 states that TOs and GOs are required to install DMEs per the requirements established by its Regional Reliability Organization (RRO). However, in the SPP region, since PRC-002-1 was never approved by FERC and with the creation of PRC-002-2, the requirements that were established by SPP on DMEs were removed from SPP Planning Criteria in April 2017. Currently, the SPP RTO has no DME installation requirements, therefore, the entities in the SPP region do not have a set of criteria to follow to meet the requirements in PRC-018-1 (particularly for requirements R4 and R5, where DME equipment required by the RRO is not specified). OKGE believes PRC-018-1 should be retired prior to PRC-002-2‘s full implementation (i.e 7/1/2022).

Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP agrees with the retirement of PRC-015-1 requirements R1, R2, and R3 since they will be superseded by PRC-012.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees that PRC-015-1 and PRC-018-1 should continue on their present scheduled paths toward being retired/superseded.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

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	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 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	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit: IRO-002-5, Requirements R4 and R6; IRO-008-2, Requirement R6, and TOP-001-4, Requirements R16 and R17. Do you agree with the SDT's recommendation to retain these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
TOP-001-4 R16 and R17 do not provide a reliability benefit. They don't even align with most, if not all, standard business processes. The Outage Coordinator, SCADA EMS, IT Networking, and Communications departments determine the impacts of all "Planned" outages or telemetry equipment. Most System Operators do not even have the technical knowledge to make substantiated decision to delay or postpone this work. Our System Operators may approve "Unplanned" outages but this is a rare exception and is not in scope for these requirements. Other requirements, such as R13 are already in place which demand an extremely high availability of EMS functionality, EMS & IT staff are well aware that unplanned outages impacting the ability to view and solve contingency analysis are unacceptable for anything other than a brief interruption.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes the requirements above can be retired without substantive reliability impact consistent with the justifications provided in the SER SAR.	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

AZPS shares the opinion of many others in the industry that the language in requirements TOP-001-4 R16 and R17 does not, in and of themselves, provide any reliability benefit. Simply having "the authority to approve outages and maintenance" does not assure that an approval occurs, nor is it required to be compliant. Since a simple letter or procedure stating that operators have the stated authority is adequate to demonstrate compliance, this action does not provide a reliability benefit.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment

GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy recommends the drafting team consider IRO-008-2 R6 for immediate retirement. We agree with the drafting team's assertion in the Technical Justifications document that characterizes R6 as administrative in nature. We do not believe that there is much if any reliability benefit in requiring an RC to notify the TOPs or BAs of any SOL/IROL exceedance that was prevented or already mitigated. There is already an Operating Plan in place to be followed for such an event, and alerting Operators of an issue that they are already aware of, and potentially distracting them from dealing with other Real-time issues, is of minimal reliability benefit.

Likes 0	
Dislikes 0	

Response

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer	No

Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC does not believe that TOP-001-4, Requirements R16 and R17 to "provide its System Operators with the authority to approve outages and maintenance of its telemetering and control equipment…" themselves provide a reliability benefit. Furthermore, we believe that this "authority" is inherent in "acting to maintain the reliability of its TOP/BA Area via its own actions or by issuing Operating Instructions" as is required by TOP-001-4, Requirement R1 and R2, and as such, R16 and R17 are not needed.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID believes these requirements the SDT has identified as inappropriate for retirement should proceed to ballot as proposed retirements based on the original SAR and recommendations from the SER Phase I teams. This would allow the Registered Ballot Body to vote on whether these requirements are appropriate for retirement or if additional work is necessary. If the retirement of these requirements do not pass ballot, IID supports that they be considered as part of SER Phase II, however the SDT should ensure the SER Phase II scope clearly indicates they will address requirements. Note that the current SER Phase II scope and six efficiency concepts does not indicate they will be addressing specific requirements.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
In regard to IRO-002-5 R4, it should be retired as approving planned outages is a reliability related task and can be easily incorporated into the current PER-005 standard. Although the requirement has a benefit to reliability, it should fall within the Operator Training standards. Therefore, the retirement of this standard requirement would be appropriate.	

In regard to IRO-002-5 R6, this requirement administrative in nature and duplicative and should be retired based on the following reason/s:

Before an entity is allowed to function as a Reliability Coordinator, it goes through a certification process, which ensures that the entity has all the relative systems in place to perform system monitoring and assessments. In addition, the certification review also involves determining if the entity's data/voice communication systems have redundancy, the ability to effectively transfer data and has alarms built in to notify System Operators in the event of adverse changes to the system.

Furthermore, the RC function is on a 3-year audit schedule by the RRO and therefore, the RC will have to continuously show that it has these same capabilities.

In regard to IRO-008-2, R6, we see no reliability benefit in this requirement as both the RC and the impacted entities will already have sufficient monitoring systems in place to ensure that all are aware when a potential SOL/IROL has been prevented/mitigated. The specific actions that the RC took to prevent/mitigate the exceedance only benefits reliability from a possible teaching point to System Operators, who may experience the same type of event in the future.

However, from an operational reliability standpoint, there is no benefit to the RC notifying entities of the actions taken to prevent/mitigate and exceedance and takes the RC's attention away from performing its responsibility to continuously monitor and assess the system.

We believe that TOP -001-4 R16 and R17 should be retired as the authority to approve planned outages is a reliability related task that can easily be incorporated into the current PER-005 standard. Although the requirements do benefit reliability, they should fall within the Operator Training standards. Therefore, the retirement of these requirements would be appropriate.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

ISO-NE recommends to review the retirements of these requirements as part of Phase 2

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	

Comment

LDWP agrees with the SDT's recommendation.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	

Comment

Please refer to comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

IRO-002-5 and IRO-008-2 were not reviewed as we are not a RC and therefore the standards are not applicable. Minnesota Power agrees with NSRF's recommendation for TOP-001-4.

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

SRC recommends that the retirement of these requirements be reviewed as part of Phase 2.

Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
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	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
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	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. The SDT is proposing to retire FAC-008-3, Requirements R7 and R8. Do you agree with the SDT's proposal to retire these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

Additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003-3 and should be a separate project.

Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Due to the importance of the use of accurate Facility Ratings in reliable BES operations and planning, Texas RE recommends FAC-008-3 R7 and R8 remain effective in order to emphasize the need to provide accurate Facility Ratings to entities that require Facility Rating data. These Requirements place an emphasis on the provision of accurate Facility Ratings to the entities responsible for the operation and planning of the BES. Although IRO-010 and MOD-032 data specifications will likely address the provision of Facility Ratings to the these entities, the large quantity of additional data potentially included within the data specifications can lead to a reduced emphasis on the Facility Rating component of the data specification. FAC-008-3 R7 and R8 would focus an entity on a specific facet of data and data exchange.

Moreover, FERC Order 693 Paragraph 771 directed NERC to develop modifications to FAC-008-1 to "for each facility, identify the limiting component and, for critical facilities, the resulting increase in rating of that component is no longer limiting". Requirement R8 meets this directive by requiring "Identity of the existing next most limiting equipment of the Facility (R8.1) and "The Thermal Rating for the next most limiting equipment (R8.2).

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG agrees with RSC position.

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 Dominion, Con-Edison

Answer	No
Document Name	

Comment

We recommend a separate standards development project be initiated to holistically address issues identified during the periodic review of FAC-008-3 and the potential retirement of FAC-008-3 requirements identified during the Standards Efficiency Review. On March 18, 2010, Docket No. RR09-6-000, FERC issued an order directing NERC to propose modification of electric reliability organization rules of procedure. This order included FERC's concerns regarding facility ratings and limiting elements. (Please see paragraph 13 and 14 of the FERC order.) We believe that additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003 to ensure that most limiting elements are determined. The equipment data that is required to be provided per the other reliability standards may not be sufficient to determine Facility Ratings, including for use in Real Time Models.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No
Document Name	

Comment

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	
Comment	
Additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003-3 and should be a separate project	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	
Comment	
The redline version of FAC-008-3 provided by the SDT does not appear to be the same as the version posted on the NERC website under 'Mandatory Standards Subject to Enforcement'. However, the wording of the Requirements proposed for retirement is the same.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
While we do not oppose the retirement of R7 and R8, we note that some aspects of R8 were added to address a FERC directive in Order 693. The Commission was so intent on this directive that it ordered NERC to modify its Rules of Procedure in a March 18, 2010 Order (Docket No. RR09-6-000) to better accommodate FERC directives in the Standards development process. FERC denied a NERC request for a stay on making further modifications to FAC-008 in September 2010. This ultimately led to development of FAC-008-3 and the addition of R8 under Project 2009-06. FERC approved FAC-008-3 in an order issued on November 17, 2011 (Docket No. RD11-10). The drafting team should consider whether the standards referenced in the technical rationale supporting retirement of R7 and R8 (MOD-032-1, IRO-010-2, and TOP-003-3) adequately address R8, part 8.2.	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation supports the retirement of FAC-008-3 Requirements R7 and R8.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	

Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	

5. The SDT is proposing to retire FAC-013-2, Requirements R1, R2, R4, R5 and R6 (all). Do you agree with the SDT's proposal to retire FAC-013-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy would like to reiterate its opposition to the retirement of FAC-013-2.

An explanation addressing how FERC's concerns in Orders 693 and 729 are still addressed needs to be provided. As stated in introduction with the Whitepaper published with the standard in Project 2010-10:

"Through FERC Orders 693 (paragraphs 782 and 794) and 729 (paragraphs 278, 279, 289, 290 and 291), FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon and communicate the results. In the FERC Order approving the MOD standards related to ATC/AFC calculations (MOD-001, MOD-028, MOD-029, and MOD-030), FERC did not approve NERC's request to withdraw FAC-012-1, nor did they approve the retirement of FAC-013-1. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards.

• The Commission noted that, under FAC-012-1, Reliability Coordinators and Planning Authorities would be required to document the methodology used to establish interregional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon.

• The Commission also noted that, under FAC-013-1, Reliability Coordinators and Planning Authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon.

• The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

• The Commission also noted, that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System.

• The Commission stated that the responsibility for calculation of transfer capabilities in the planning horizon would be appropriately assigned to the Planning Coordinator and not the Reliability Coordinator.

Consistent with the above philosophy and to address FERC's concerns, FAC-013-2 requires that Planning Coordinators have a current documented methodology for use in performing an annual assessment of Transfer Capability in the Near-Term Planning Horizon (Transfer Capability Methodology)."

In the Technical Justification document, the SDT states that:

"The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards."

Assuming that the drafting team is referencing TPL-001 in the above statement, we would like to point out that TPL-001 standard does not REQUIRE that transfer sensitivities be performed and are not likely to indicate limitations to transfer from neighboring systems which is indicative of a neighbor's ability to support a system during an energy emergency. In its response to comments the SDT agreed that at some point in the future it would be appropriate to move the requirements of FAC-013-2 into the TPL standards. This was not possible at the time due to the timing requirements necessary to meet FERC's orders. In addition the SDT's Whitepaper stated:

"The TPL standards define the studies to be performed, the performance requirements for the BES and the details of the required assessments. FAC-013-2 is intended to identify potential future weaknesses in the system by performance of tests - application of bulk energy transfers to stress the system. FAC-013-2 adds to the understanding of system performance obtained through application of the TPL standards, providing knowledge of potential facilities requiring additional focus and analysis."

The Technical Justification document also states that:

"This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities."

We disagree with the coordination reference in the above statement. Coordination occurs through sharing of identified limits to transfer through R2 for awareness and any necessary action.

Next, the Technical Justification document states that:

"Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability."

We disagree with the statement that this is solely related to a market function. Transfers serve to stress test the system in ways that the PC deems best to identify weak points on their system and impacts on their neighbors. The Whitepaper published with the standard stated, "In addition, this information is not intended in any way to be associated with the granting or denial of transmission service."

"Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments."

While it is true that there is no obligation to use or consider the information in the assessment, as is the case with TPL-001, but the results are required to be shared with neighboring systems. The Whitepaper states "The application of FAC-013-2 will provide an assessment of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. FAC-013-2 addresses FERC's concerns regarding transfer capability in the planning horizon and provides important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES."

"Requirement R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability."

The standard is supposed to provide a stress test as best determined by the PC's operating experience and knowledge to identify future system weaknesses. The Whitepaper states "AC-013-2 allows the Planning Coordinator to develop its Transfer Capability Methodology based on knowledge of its system's sensitivity to transfers and significance of Facilities to reliability, within the framework provided by FAC-013-2." It is not intended to provide information regarding transmission service which is studied in a completely different way.

"Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness."

While there may not be a standard metric for robustness, assessing transfer capability in the planning horizon does add to the PC's portfolio of knowledge of their system's behavior under stressed conditions.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) The California ISO has the following additional comment: "If FAC-013-2 is retired, then FAC-015 development under Project 2015-09 needs to be revisited, as those activities were premised on FAC-013 continuing to be in effect and modified to FAC-013-3 as part of the comprehensive changes within Project 2015-09."	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP believes FAC-013-2 needs further refinement and standardized metrics so that all Planning Coordinators are following a standard methodology.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
It is important to coordinate the retirement of FAC-013-2 with the retirement of FAC-014-2 under NERC Project 2015-09 Establish and Communicate System Operating Limits. The planning level SOLs required under R3, and R4 of FAC-014-2 are usually established based on the FAC-013-2 Transfer Capability Assesment.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
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	

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
FAC-013-2 was not reviewed as we are not a PC.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

6. The SDT is proposing to retire INT-004-3.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-004-3.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes the retirement of the INT-004 requirements should be contingent upon the FERC adoption of the corresponding NAESB standards. NAESB standards do not apply equally to industry participants (e.g., not applicable to non-jurisdictional entities).

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

INT-004-3.1 should not be retired until NAESB BPS WEQ-004 version 3.1, 3.2 is approved by FERC concerning Dynamic and Pseudo-Ties schedules.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy disagrees with the proposed retirement of INT-004-3.1. In the Technical Justification document, the drafting team categorizes INT-004-3.1 as more of an impact on transmission costs, rather than reliability. While costs and pricing do not directly impact the reliability aspects of the grid, ensuring levels of transfer and practicing congestion management help to ensure reliability of the grid.

Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
ACES recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern would support retiring these requirements after they have been reviewed for inclusion into the NAESB WEQ Business Standards and subsequently ratified by FERC.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF’s recommendation.	
Likes 0	

Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	

Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
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	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

7. The SDT is proposing to retire INT-006-4, Requirements R3.1, R4, and R5. Do you agree with the SDT's proposal to retire Requirements R3.1, R4, and R5 of INT-006-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy disagrees with the proposed retirements for INT-006-4. We are not confident that this issue is adequately covered in the NAESB standards. Unlike the NERC standards which aim to promote reliability, the NAESB standards are commercially focused, and are not viewed as essential to maintaining a reliable system. We believe that not having these conditions outlined, could negatively impact reliability.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

Disagree, R4, R5 - North American Energy Standards Board (NAESB) e-Tagging specifications is not part of WEQ Business Practice Standards or approved by FERC, this will leave a responsibility gap for compliance.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Idaho Power does not agree with retiring the R3.1 and R5 requirements.

R3.1: It is important to define how long an entity has to approve or deny interchange.
R5: Notification in a timely manner is needed.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment

PJM supports the partial retirement of these standards.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF’s recommendation.	
Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
R3.1 – There is no impact on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. The RC is already notified of a denial via E-tag as required in the NAESB e-Tagging Specifications. R4 & R5 are duplicative of the NAESB e-Tagging Specifications Section and are not a reliability-related task performed by a NERC registered entity.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
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	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

8. The SDT is proposing to retire INT-009-2.1, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of INT-009-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The requirement is redundant and qualifies for retirement under Paragraph 81. The requirement for BAs to establish an agreed upon interchange meeting source is covered in BAL-005-1 R7.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	
Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM supports the partial retirement of these standards.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	

Response

9. The SDT is proposing to retire INT-010-2.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-010-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE agrees that the specific content of INT-010, creating an RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3 proposed as part of this effort continues to reference INT-010. Therefore, ISO-NE recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
Although AZPS agrees these requirements can and should be retired, their retirement must be done in coordination with changes to INT-009-2.1 R1, which references INT-010-2.	
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 Dominion, Con-Edison	
Answer	No
Document Name	
Comment	
NPCC agrees that the specific content of INT-010, creating RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3	

proposed as part of this effort continues to reference INT-010, Therefore, NPCC recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees with the drafting team's proposal to retire this standard. The technical rationale document states that this standard can be retired because more stringent tagging requirements already exist under NAESB. Unlike the NERC standards which aim to promote reliability, the NAESB standards are commercially focused, and are not viewed as essential to maintaining a reliable system. While part of INT-010-2.1 may be commercial in nature, we believe that the standard generally supports the reliability of the grid. Also, NAESB is only applicable to jurisdictional entities. Not all entities that are currently NERC Registered Entities, fall under the jurisdiction of NAESB, and would not be required to adhere to any of its business practices.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Disagree, NAESB WEQ BPS 004-1.7 reference NERC INT-010-2.1 R1 for energy sharing groups for conditions not submitting eTags. Not approved by FERC.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No

Document Name	
Comment	
OPG agrees with RSC position.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of the standard be contingent upon a new NAESB WEQ-004 requirement becoming effective which allows interchange fitting the current INT-010-2.1 criteria to be implemented without an RFI. Such a requirement is currently published as WEQ-004-1.7 under the NAESB WEQ version 3.2 standards. However, the WEQ-004-1.7 requirement would need to be revised. Without this NAESB requirement, a Balancing Authority would not be able to implement interchange transactions described in INT-010-2.1 without an associated RFI which could jeopardize the reliability of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes

Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of the Standard be contingent upon a new NAESB WEQ-004 requirement becoming effective which allows interchange fitting the current INT-010-2.1 criteria to be implemented without an RFI. Such a requirement is currently published as WEQ-004-1.7 under the NAESB WEQ version 3.2 standards. However, the WEQ-004-1.7 requirement would need to be revised. Without this NAESB requirement, a Balancing Authority would not be able to implement interchange transactions described in INT-010-2.1 without an associated RFI which could jeopardize the reliability of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes

Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	
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 the specific content of INT-010, creating an RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3 proposed as part of this effort continues to reference INT-010. Therefore, the SRC recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
R1, R2 and R3 are redundant because more stringent requirement(s) that meet the objectives are already included in the NAESB standards (WEQ-004-1 & WEQ-004-8) due to their commercial purposes. These requirements do little, if anything, to benefit or protect the reliable operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements. However, because INT-009-2.1 Requirement R1 refers to INT-010-2, it may be preferable to defer consideration to the retirement of the requirements in INT-010-2.1 to the SER Phase II effort.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

10. The SDT is proposing to retire IRO-002-5, Requirement R1. Do you agree with the SDT's proposal to retire Requirement R1 of IRO-002-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
We believe the other requirements of IRO-002-5 are fundamentally based upon R1, as this requirement mandates RCs to have data exchange capabilities. Other requirements in this standard refer to this term periodically. As such, eliminating this requirement would diminish clarity regarding expectations in the remaining requirements. If R1 is retired it could be merged with R2 so that there is a single requirement discussing all data exchange capabilities needed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned that if IRO-002-5 Requirement R1 was eliminated, Reliability Coordinators may not put emphasis specifically on having data exchange capabilities with their Balancing Authorities and Transmission Operators. This could also lead to a larger engagement scope and the inclusion of IRO-008-2 R1, and IRO-010-2 Requirements R1, R2, and R3, instead of just including IRO-002-5 Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern believes that this requirement should be retired as it does not add any additional benefit to reliability. Before an entity is certified to perform the RC function, it must first demonstrate that it has adequate communications (both data and voice) to communicate with BAs and TOPs in its RC area and with those entities adjacent to its RC area. In addition, the RC function is on a 3 year audit cycle and must continue to demonstrate that it has those communication capabilities to remain certified.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	

Comment

Please refer to comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
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	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 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	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

IRO-002-5 was not reviewed as we are not a RC and therefore the standard is not applicable.

Likes 0	
Dislikes 0	

Response

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	Attach_DE_SER Question 11_Apr 2019.docx
Comment	

While Duke Energy would support the retirement of these MOD standards, we cannot do so if MOD-001-2 is withdrawn. The MOD standards promote reliability of the grid by putting in place common boundaries and provisions that are necessary for various calculations that need to be performed. These calculations are important to reliability by providing the baseline for understanding the operational need. By retiring the MOD standards, and not having MOD-001-2 in place, there will not be provisions in place to aid an entity in calculating transfer capability. There will not be any boundaries in place for the curtailment of service. We disagree with the commercial based focus that the drafting team took in the technical rationale document. While these MOD standards (and ATC calculation) may have some commercial based elements to them, they also put in place valuable boundaries that help promote consistency in how the industry calculates these values. Removing these boundaries does not promote reliability for the Bulk Electric System and introduces additional burden to the real-time System Operator.

The expectation of the System Operators to ensure the reliability of the BES in the real-time when there have been no requirements to ensure how ATC is calculated or coordinated beyond what is required by NAESB is unrealistic. Some of the most glaring issues with relying solely upon NAESB to regulate the calculation of ATC are: FERC does not have oversight for non-jurisdictional TSPs and therefore cannot require them to incorporate NAESB standards. Also, while NAESB has acted on the recommendations of the MOD-A project to incorporate any of the gaps created by the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and adoption of MOD-001-2, FERC has not acted on either the NERC or NAESB filings. Further, NAESB has not been requested to modify proposed standards to incorporate any of the gaps created by the retirement of the proposed MOD-001-2.

Additionally, the lack of any NERC regulation for consistent ATC methodologies and requirements for sharing of data and could potentially lead to an increase of TLRs being called as this would be the only tool System Operators could utilize to combat rampant loop flow impacts on the BES. This could very well lead to capacity concerns and load shedding as the increase in TLRs could include firm curtailments causing capacity shortages. Without mandatory ATC standards, a TSP would be able to sell as much service as possible. The overselling of service and the overscheduling of ATC Paths will lead to an increase of FIRM TLR, potentially forcing Transmission Operators and Load Serving Entities to shed FIRM load to comply with the TLR. Over the past eight years the MOD-001, 28,29, & 30 standards have been effective the industry has seen a dramatic reduction in FIRM TLRs.

Included in the Attachment with Duke Energy's response to this question is the rolling 12-month average of TLRs from the NERC website. Notice the reduction in TLRs from 2008-2011 when the MOD standards were first published (in 2008 when TSP started to incorporate the MOD standards into their ATC methodologies) and 2011 (when the MOD standards were mandatory and enforceable).

Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.

Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

No comments.

Likes 0	
Dislikes 0	

Response
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.

Likes 0	
Dislikes 0	

Response
Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

See response to Q17.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

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	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	

Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

12. The SDT is proposing to retire MOD-008-1, Requirements R1, R2, R3, R4, and R5 (all). Do you agree with the SDT's proposal to retire MOD-008-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA disagrees with the retirement of these standards at this time.

Until a resolution is reached on NAESB's WEQ-023, and these items are incorporated by reference per the FERC Commission, retirement of these MOD Reliability Standards would leave a significant gap of reliability of ATC in the industry. WEQ-023 (submitted under Version 003.1) was not approved by the Commission to be incorporated by reference at this time and is being considered under an overall inquiry into ATC calculation. This leaves the standard, as written in NAESB as voluntary. MOD-001-2 was drafted with the mindset of leaving only reliability aspects of ATC under NERC oversight and WEQ-023 being approved by the Commission. If MOD-001-2 is withdrawn, there would be no reliability push for ATC requirements under FERC and could potentially cause further delay. Removal of these standards could impact the transparency that is established with sharing data with neighbors as well.

According to Project 2012-05 ATC Revisions (MOD A), MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

The WEQ-023 standards drafted did not incorporate honoring neighboring systems nor ensure an entity have an ATCID, or TRMID, or CBMID because the thought was that it would be laid out in the NERC space under MOD-001-2. So NAESB would have to incorporate all of this into the business practice, which would blur the lines of reliability and commercial that the project was developed to address.

TVA agrees with the goal of the Standards Efficiency Review Team to decrease the number of requirements and make the standards less confusing and less burdensome. Yet, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and ignoring the impact on your system, this too will affect your reliability. This does not just impact transmission costs as some would believe.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT is not opposed to the retirement of these requirements.

Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 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	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	

13. The SDT is proposing to retire MOD-028-2, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, and R11 (all). Do you agree with the SDT's proposal to retire MOD-028-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	

Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

14. The SDT is proposing to retire MOD-029-2a, Requirements R1, R2, R3, R4, R5, R6, R7, and R8 (all). Do you agree with the SDT's proposal to retire MOD-029-2a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

The current standard addresses aspects that are commercial in nature.

The reliability assessment requirement for determining transfer limits is addressed in FAC-11

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	

Comment

LDWP agrees that this standard no longer directly impacts system reliability. However, there should be a standardization of TTC/ATC calculation so that there is uniformity between entities.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

See response to Q17.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	

Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	

Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	

Likes 0	
Dislikes 0	
Response	

15. The SDT is proposing to retire MOD-030-3, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9 and R10 (all). Do you agree with the SDT's proposal to retire MOD-030-3? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA disagrees with the retirement of these standards at this time.

Until a resolution is reached on NAESB's WEQ-023, and these items are incorporated by reference per the FERC Commission, retirement of these MOD Reliability Standards would leave a significant gap of reliability of ATC in the industry. WEQ-023 (submitted under Version 003.1) was not approved by the Commission to be incorporated by reference at this time and is being considered under an overall inquiry into ATC calculation. This leaves the standard, as written in NAESB as voluntary. MOD-001-2 was drafted with the mindset of leaving only reliability aspects of ATC under NERC oversight and WEQ-023 being approved by the Commission. If MOD-001-2 is withdrawn, there would be no reliability push for ATC requirements under FERC and could potentially cause further delay. Removal of these standards could impact the transparency that is established with sharing data with neighbors as well.

According to Project 2012-05 ATC Revisions (MOD A), MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

The WEQ-023 standards drafted did not incorporate honoring neighboring systems nor ensure an entity have an ATCID, or TRMID, or CBMID because the thought was that it would be laid out in the NERC space under MOD-001-2. So NAESB would have to incorporate all of this into the business practice, which would blur the lines of reliability and commercial that the project was developed to address.

TVA agrees with the goal of the Standards Efficiency Review Team to decrease the number of requirements and make the standards less confusing and less burdensome. Yet, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and ignoring the impact on your system, this too will affect your reliability. This does not just impact transmission costs as some would believe.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

16. The SDT is proposing to retire MOD-001-1a, Requirements R1, R2, R3, R4, R5, R6, R7, R8 and R9 (all). Do you agree with the SDT's proposal to retire MOD-001-1a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

See response to question 11.

Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	No
Document Name	

Comment	
MOD001 requires that all registered TOPs establish reliability boundaries in which the TSPs can operate to maximize energy business transactions. By moving MOD-001 from under NERC responsibility, the BES reliability may be compromised. Transfer capability includes the impact on other areas due to the transfer of electric power.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
MOD-001-1a allows Transmission Operators to select, on the record, the methodology for computing the Available Transfer Capability in a standardized manner, which is the foundation for establishing the quantity of transmission capacity, in excess of native load needs and existing commitments, that may be sold to wholesale transmission customers in a fair and transparent fashion via Open Access Same-Time Information System (OASIS). Absent MOD-001-1a or its successor that meets the same objective, Transmission Operators may be at liberty to craft methodology to calculate ATC that may not be in alignment with the industry. This condition, if it prevails, will lead to unfair practice wherein some Transmission Operator may be held to a higher standard while others will be held to a lower standard. This, in turn, creates a less transparent environment for transmission customers to assess how Transmission Operators derive ATC.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	

Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
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	

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 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	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	

17. The SDT is proposing to withdraw Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities. Do you agree with the SDT's proposal to withdraw Reliability Standard MOD-001-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Chris Wagner - Santee Cooper - 1

Answer	No
Document Name	

Comment

Recommend that the revised MOD-001-2 move forward as the current in force MOD-001 standard.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

NERC petitioned FERC for approval of MOD-001-2 in February 2014. The implementation plan called for the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2. In the petition, NERC characterized the purpose of MOD-001-2 as helping to "ensure that determinations of ATC and AFC are accomplished in a manner that supports the reliable operation of the Bulk Power System." MOD-001-2 was developed under NERC's standard development process and was adopted by the NERC Board of Trustees. Now, five plus years after the petition was filed, and with no publicly visible action by FERC on the petition beyond a NOPR issued in June 2014, the SER drafting team is suggesting the petition for MOD-001-2 be withdrawn. It's not clear how the Real-time operators monitoring of SOLs and IROLs helps ensure that determinations of ATC and

AFC are accomplished in a manner that supports the reliable operation of the Bulk Power System. If there are no standards addressing the determinations of ATC and AFC, you can expect that Real-time operators will be dealing with more SOLs and IROLs in the future.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern continues to disagree with the SDT's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards would strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. However, since FERC has not yet approved MOD-001-2 nor has not yet taken any action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those standards until they are subsequently approved by the Commission (FERC). Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes

Document Name	
Comment	

PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.

Likes 0	
Dislikes 0	
Response	

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	
Comment	

MOD-001-1a allows Transmission Operators to select, on the record, the methodology for computing the Available Transfer Capability in a standardized manner, which is the foundation for establishing the quantity of transmission capacity, in excess of native load needs and existing commitments, that may be sold to wholesale transmission customers in a fair and transparent fashion via Open Access Same-Time Information System (OASIS). Absent MOD-001-1a or its successor that meets the same objective, Transmission Operators may be at liberty to craft methodology to calculate ATC that may not be in alignment with the industry. This condition, if it prevails, will lead to unfair practice wherein some Transmission Operator may be held to a higher standard while others will be held to a lower standard. This, in turn, creates a less transparent environment for transmission customers to assess how Transmission Operators derive ATC.

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas

City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	

Dislikes 0	
Response	

18. The SDT is proposing to retire MOD-020-0, Requirement R1 (all). Do you agree with the SDT's proposal to retire MOD-020-0? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Although ACES agrees with the retirement of this Standard, the technical justifications for retirement of requirement 1 requires additional clarification as it creates confusions. More specifically, SAR suggests a different justification than what was provided in slides versus slide 17 from the Industry Webinar which was held on 3/21/19 Outreach Webinar.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Duplicative of data provision requirements in MOD-031-2 and IRO-010-2 standards	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

19. The SDT is proposing to retire PRC-004-5(i), Requirement R4. Do you agree with the SDT’s proposal to retire Requirement R4 of PRC-004-5(i)? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT’s proposal, please provide your explanation.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison

Answer	No
Document Name	

Comment

The retirement of PRC-004-5(i) could potentially burden the entity with an open item, with no closing date, hoping that a new technological break-through will finally determine the cause of misoperation. We believe entities will simply declare that no cause for the misoperation was identified and be done with it.

If R4 is retired, one or both of the following approaches will likely be taken by entities:

· Delaying formal declaration of a misoperation for all disturbances until the root cause is identified or until 120 days expires.

· Declaring the cause for a greater percentage of misoperations as “unknown” and not performing the detailed testing to find the true root cause for an issue that is intermittent.

This is not beneficial to the goal of reliability improvements and reduced misoperations.

We recommend that the SDT consider how the ability to declare that “no cause of a misoperation was identified” be retained within the standard to document the end of an investigation. We are concerned that the removal of the ability to declare that no cause of a misoperation was identified may result in audit and compliance concerns.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	No
Document Name	

Comment

If R4 is retired, one or both of the following approaches will likely be taken by entities:
• Delaying formal declaration of a misoperation for all disturbances until the root cause is identified or until 120 days expires.
• Declaring the cause for a greater percentage of misoperations as “unknown” and not performing the detailed testing to find the true root cause for an issue that is intermittent.
This is not beneficial to the goal of reliability improvements and reduced misoperations.

Likes 0	

Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with RSC position.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned that eliminating a requirement to investigate and track Misoperations could lead to entities not investigating the cause of a Misoperation. The SDT states the Requirement R4 acts as a control to support Requirements R1 and R3. Requirements R1 and R3 are different though, in that they are in place to determine *whether or not a Misoperation occurred*. Requirement R4 is to determine the *cause* of the Misoperation. Understanding the cause of a Misoperation can help prevent Misoperations in the future. Indeterminate causes of Misoperations are difficult issues that can provide valuable lessons for all entities involved in system protection. Protection System Misoperations continue to be a significant reliability risk factor and exacerbate the impact of transmission outages. In the 2017 State of Reliability Report, 9% of the Misoperations were categorized as "Unknown/Unexplainable". The 2018 State of Reliability Report noted that "Protection system Misoperation should remain an area of focus, as it continues to be one of the largest contributors to the severity of transmission outages." The 2018 State of Reliability report shows no decline in the percentage (9%) which is indicative that more focus is needed. Tracking the issues, if actively pursued, may help entities across the ERO understand complex issues when the cause of a Misoperation is identified. Removal of this Requirement disincentivizes an entity in continuing to find Misoperation causes which then, if found, be used to improve reliability.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
ERCOT does not support the outright retirement of PRC-004-5(i), Requirement R4 because to do so would eliminate the requirement to investigate in its entirety. However, ERCOT agrees that the Requirement as written may impose unnecessary burden by requiring repeated investigations despite the potential inability of a Transmission Owner, Generator Owner, or Distribution Provider to identify the cause(s) of a Misoperation.	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	Project 2018-03 PRC-004-6 R4 Comments.docx
Comment	

ReliabilityFirst does not agree with the removal of PRC-004-6 Requirement R4 for the following reason:

The concept of a declaration for no identifiable cause is currently introduced in R4 and in the Application Guidelines (now called Supplemental Material) for R4. The one statement from the Application Guidelines for R4 in version 5(i) states,

> 'The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.'
>
> This statement needs to be retained somewhere as an explanation for this use of the declaration. The declaration is also referenced in R5, but for a different reason (problem found but CAP won't improve reliability of BES). The declaration associated with R4 would be a cause that is 'unknown/unexplainable' and all testing and analysis comes up empty. There wouldn't be a CAP, since nothing was found broken, and the declaration is used to close the investigation. In MIDAS, the CAP Completion Status would be 'declaration' rather than improperly coding as 'CAP – Complete', since no CAP was developed.
>
> As far as the administrative requirement of 'corrective action at least once every two calendar quarters', ReliabilityFirst recommends the following for consideration (see attached as well for redline of requirment):

R4:

Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation [maintaining documentation in sufficient detail to provide clear delineation of the stage and findings of the investigation] until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*

☐ The identification of the cause(s) of the Misoperation; or

☐ A declaration that no cause was identified.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP does not agree that PRC-004-5(i) R4 meets the drafting team's "Evaluation Criteria for Retiring Reliability Standards Requirements", as the declaration of "no cause found" is made only within this obligation (i.e. "is not redundant"). Regarding the reliability rationale, we would agree that not all investigative actions in and of themselves improve reliability, however the ability to track investigative actions over an extended period of time ensures more rigor is applied to the investigative progress.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

NA to ISO-NE and repeated attempts to determine a cause of relay misoperations as described by R4 don't appear to be productive.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	Yes
Document Name	

Comment

Reclamation supports the retirement of PRC-004-5(i) Requirement R4. Reclamation recommends PRC-004-5(i) Requirement R5 be split into two requirements: one to develop a corrective action plan or explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken; and one to evaluate the corrective action plan for applicability to the entity's other Protection Systems including other locations.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

we are concerned that simply retiring this requirement could create some unintended negative consequences. As it is well understood, not all misoperations can be definitively determined no matter how detailed or thorough the investigation. It is for this reason that earlier SDTs included in Requirement R4 the ability to declare that no cause could be determine as part of the Misoperation Identification and Correction process. It is also noteworthy to mention that Requirement R4 is the only requirement within this standard that allows such a declaration. Therefore, care will be needed when retiring Requirement R4 to ensure that language is added to the standard to ensure this important ability and right held by TOs, GOs and DPs is not lost. To better understand this concern, EEI suggests that a thorough review of the flowchart (see R4) on Page 36 of PRC-004-5(i) is conducted by the responsible SDT."

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees that the investigative actions conducted for Misoperations do not directly improve BES reliability, and thus Requirement R4 should be retired. However, Entities are still required to provide quarterly reports to MIDAS on misoperation types and causes, thus investigation is still a necessary part of this Standard. So, to capture this supplemental administrative requirement, NV Energy would recommend the SDT to modify R5 to include a situation where the cause of the Misoperations is unknown, which ais an allowable entry for cause in MIDAS. We don't think it is clear that the unknown cause can be described in the current language in R5. It is still unclear if an R5 declaration within a CAP that the actions are beyond the entities control can be tied to an "unknown" cause. Given that the R5 "60-day time requirement" starts when the cause is identified, but if the cause is unknown, when does that clock start?. If the current wording in R5 remains intact, entities can technically stop at R3 for Misoperations that it has not identified a cause. We do not believe that this is the intent of the standard. If this clarity is not provided, there is a potential that when auditing the Requirement, one can determine that a cause must be identified, if there is no clear requirement that allows a cause of "unknown" to be declared.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista concurs with EEI comments: “EEI supports the retirement of PRC-004-5(i), Requirement R4; however, we are concerned that simply retiring this requirement could create some unintended negative consequences. As it is well understood, not all misoperations can be definitively determined no matter how detailed or thorough the investigation. It is for this reason that earlier SDTs included in Requirement R4 the ability to declare that no cause could be determined as part of the Misoperation Identification and Correction process. It is also noteworthy to mention that Requirement R4 is the only requirement within this standard that allows such a declaration. Therefore, care will be needed when retiring Requirement R4 to ensure that language is added to the standard to ensure this important ability and right held by TOs, GOs and DPs is not lost. To better understand this concern, EEI suggests that a thorough review of the flowchart (see R4) on Page 36 of PRC-004-5(i) is conducted by the responsible SDT.”	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
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	
Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.	

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
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	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	

MEC agrees with the SDT that investigative actions for Misoperations do not improve reliability. Therefore, we are prepared to support the SDT's draft revision to retire R4.

We would also like the drafting team to modify R5 to include a situation where the cause of the Misoperations is unknown. We don't believe it is clear that the unknown cause can be described in the R5 declaration that the CAP is beyond the entities control. The R5 60 day time requirement starts when the cause is identified. How do you start the clock to develop the CAP if the cause is unknown? The R5 declaration is after this time requirement in the standard. If the current wording in R5 remains intact, entities can technically stop at R3 for Misoperations that it has not identified a cause. I do not think this is the intent of the standard.

Another issue is that an auditor can determine that a cause must be identified if there is no clear requirement that allows a cause known declaration. There are some Misoperations (very few) where the Protection Engineer will not be able to determine a cause. The is why MIDAS has a cause unknown option.

See the PRC-004-5i flowchart and how you jump from R3 to R5 if R4 is removed.

Likes 1	Berkshire Hathaway Energy - MidAmerican Energy Co., 1, Harbour Terry
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, 6

- On Page 23 of 32 of the posted, proposed "clean" version of PRC-004-6, the sentence:

"Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins."

This sentence references the required actions in Requirement R4 of the Standard, which is to be retired. Recommend this sentence be deleted.

- On Page 24 of 32 of the posted, proposed "clean" version of PRC-004-6, in the second to the last paragraph, the phrase "under Requirement R4". Recommend this phrase be deleted.

- On Page 32 of 32 of the posted, proposed "clean" version of PRC-004-6, in the Flowchart, the area of the Flowchart leading into R5, the box labeled "Cause Known?" has only a path into R5. The Standard must still provide the option to end an investigation with no cause found.

Recommend:

- For a Misoperation with no cause found, the flowchart should also point from "Cause Unknown?" to the "Stop" circle to the left.

- Add “Yes” to the existing path from “Cause Unknown?” to R5, and “No” to the new path to “Stop”.

Likes 0	
Dislikes 0	
Response	

20. The SDT is proposing to retire TOP-001-4, Requirements R19 and R22. Do you agree with the SDT's proposal to retire Requirements R19 and R22 of TOP-001-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned that if TOP-001-4 Requirements R19 was eliminated, Transmission Operators may not put emphasis specifically on having data exchange capabilities with the entities they have identified it needs data from to perform its Operational Planning Analyses . Texas RE is concerned that if TOP-001-4 Requirements R22 was eliminated, Balancing Authorities may not put emphasis specifically on having data exchange capabilities with the entities it has identified it needs data from to perform its Operating Plan for next-day operations .	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
In regard to R19, this requirement is only administrative in nature as an entity must demonstrate that is has the ability exchange data with all entities that it provides and receives information from to perform its monitoring and assessments, to include operational planning before it can be certified to perform the TOP function. In addition, TOP entities are on a 3-year audit cycle and in which the entity's data exchange capabilities with other entities are reviewed. In regard to R22, this requirement is only administrative in nature as an entity must demonstrate that is has the ability exchange data with all entities that it provides and receives information from to perform its monitoring and assessments before it can be certified to perform the BA function. In addition, BA entities are on a 3-year audit cycle in which the entity's data exchange capabilities with other entities are reviewed.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
NPCC supports the SDTs position. However, we would consider supporting a position in which these Requirements would be recommended to the phase two analysis, and that they should be incorporated into the entity certification process.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	

Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Having data exchange capabilities does not add a reliability benefit. Something must be done with the data in order to impact reliability. The authority to request and do something with the data is adequately covered in TOP-003-3.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

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	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

21. The SDT is proposing to retire VAR-001-5, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of VAR-001-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees with the drafting team's proposal to retire VAR-001-5 R2. This requirement ensures that Operators have the necessary reactive resources they need to provide voltage control. Eliminating this requirement would take away an Operators ability to justify keeping a reactive resource in service and potentially negatively impact the reliability of the grid.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power disagrees with the proposed retirement for VAR-001-5 R5 because, while it is difficult to provide evidence for, the requirement for scheduling sufficient reactive resources is important.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Ensuring that an entity has sufficient reactive resources to regulate voltage levels under both normal and contingency conditions is an inherent function of the TOP, and although having a standard requirement may add some reinforcement, it does not necessarily add to reliability. If the TOP fails to provide adequate reactive resources to regulate voltage, it could lead to voltage collapse, damage to equipment, system overloads and blackouts. (All of which are covered in other NERC Reliability Standards). Having this standard requirement in place places an administrative burden on the TOP and takes their time away from operating the transmission system.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
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 Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

This was not reviewed.

Likes 0	
Dislikes 0	

Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment
Texas RE is concerned that without VAR-001-5 Requirement R2, Transmission Operators may not put emphasis on scheduling sufficient reactive resources to regulate voltage levels. This could lead to voltage collapse. Additionally, the SDT is relying on the fact that voltage limit is a form of an SOL. Since there is no definition of SOL exceedance, entities may not adequately address voltage issues within the OPA, whereas this requirement emphasizes regulating voltage levels. Texas RE recommends removing the reference to “Compliance Monitor” in C1.2 Data Retention. Compliance Monitor is an outdated term and there is no definition for it.

Likes 0	
Dislikes 0	

Response

22. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	

Although ACES agrees with the retirement Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-030-3 and MOD-001-2, ACES cautions the unique position of some of its members requiring them to obtain transmission service across multiple BAAs and participate in transactions between ISO/RTO and non-ISO/RTO entities. This has allowed those entities to witness first-hand the mismatched ATC values across the seams shared by adjacent Transmission Providers. For that reason, we advocated for this at that time and still hold the position that the retirement of these standards should be contingent upon analysis of their retirement impact on entities with such unique situations, like North Carolina Electric Membership Corporation (NCEMC) that depends on the transmission services to meet its load obligation, reliably and economically, within each of their BAAs.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have additional comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI member companies would like to note our appreciation to NERC for the opportunity afforded to the Industry to provide input into the planned SER Phase I Retirements (Project 2018-03). We are very supportive of those efforts as well as the deferments of some requirements to the SER Phase 2 Project. While we understand that the CIP Standards will also be addressed in the SER Phase 2 Project, we ask that NERC provide additional clarity to the Industry as to how and when these Phase 2 efforts will all tie together. Such an effort would be appreciated by the Industry and would resolve any concerns companies may have related to the Phase 2 effort.

Additionally, EEI Members have noted that when NERC originally queried the Industry for recommendations for possible Reliability Standard Requirements that merit consideration for the Phase 1 effort, the Industry was also told that the CIP Standards would not be considered until the Phase 2 effort. Now that Phase 2 is beginning, EEI looks forward to NERC "consult[ing] with the SER Advisory Group and stakeholders, on a plan to address the CIP Standards in the SER." (see NERC Standards Efficiency Review Project Update | August 3, 2018) We additionally ask NERC to provide greater clarity and detail as to when stakeholder outreach, similar to the Phase 1 Industry solicitation, will be initiated for CIP Reliability Standards? While NERC did receive a small number of CIP related suggestions within the Phase 1 solicitation, the focus was on the O&P Standards. EEI member companies believe additional solicitation focused on CIP is necessary for effectively addressing CIP Standards in Phase 2.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please refer to comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
At the onset of the Standards Efficiency Review Project NERC stated that there would be an effort to review/revise the CIP standards during phase 2 of the project. The perception by industry was that the CIP standards would go through an iteration of review/revision like the process used by NERC for the O&P standards during phase 1. Can NERC please clarify whether the CIP standards will be more closely reviewed/revised and vetted by industry in subsequent phase of this project.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support Edison Electric Institute's comments to Question 22.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Idaho Power has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy is appreciative of the efforts taken by NERC and SDT to review the reliability standards and identify these requirements and standards for retirement. As the efforts with Phase I were dedicated to the O&P Standards, NV Energy is anticipating that in Phase II that this same in-depth review will be conducted for the CIP Standards and Requirements. NV Energy is also looking forward to the inventory of requirements that will be identified with the application of the concepts for the Phase II review.	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Additional comments submitted by Duke Energy

Duke Energy Comment Response to Question 11: for 2018-03 Standards Efficiency Review Retirements comment period ending on: 4/12/2019 8:00 PM

Question:

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes

☒ No

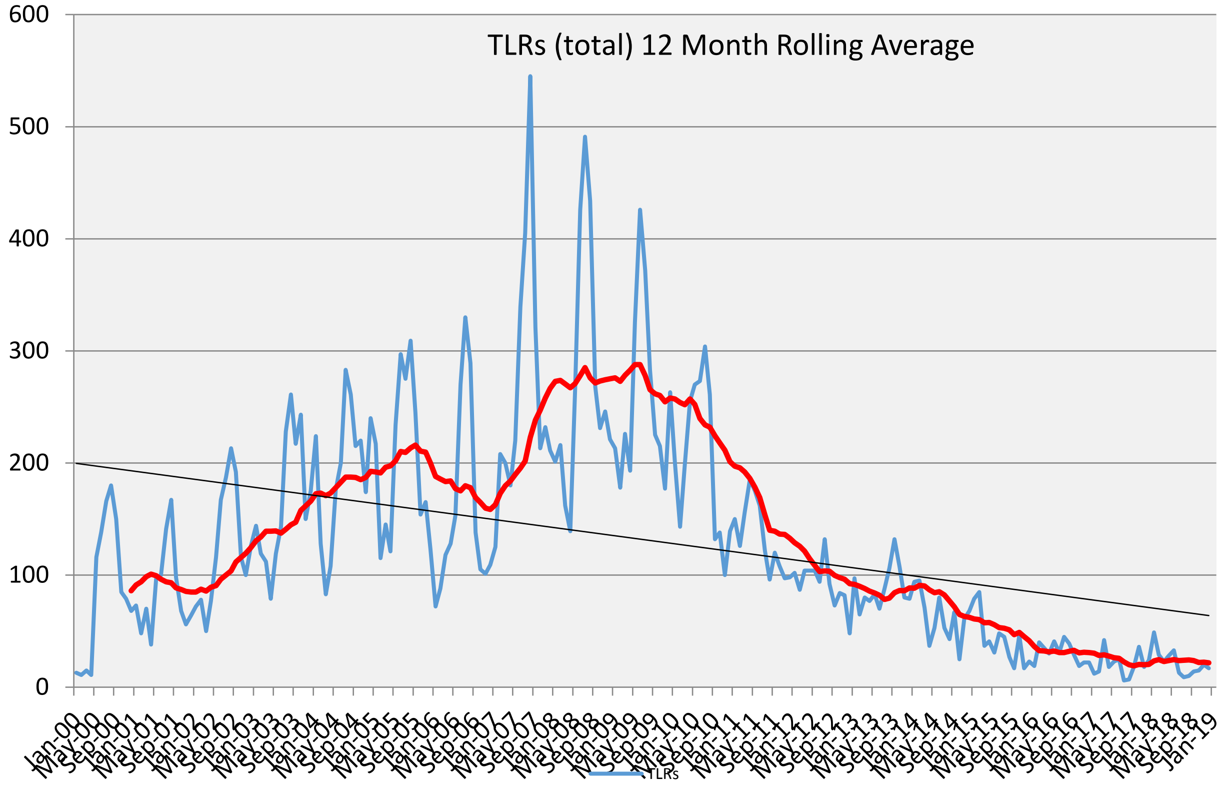
Comments:

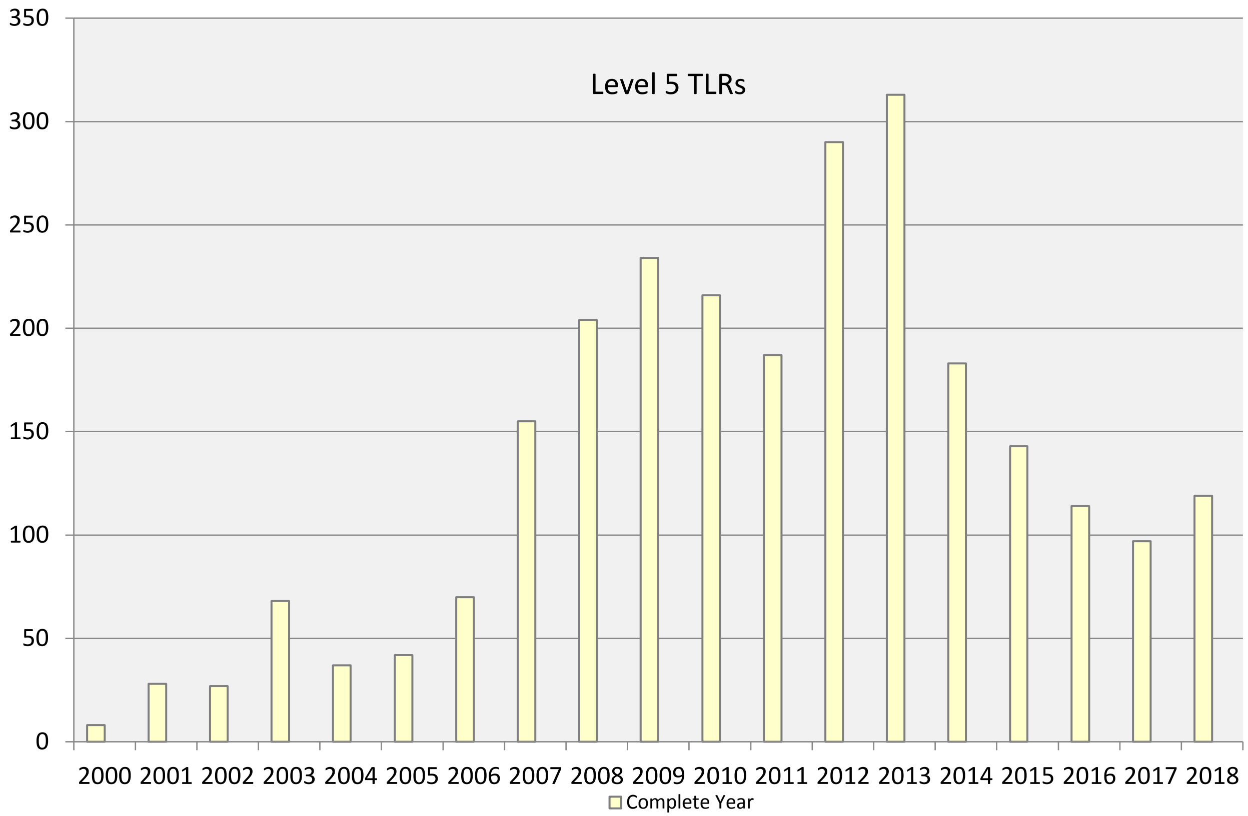
While Duke Energy would support the retirement of these MOD standards, we cannot do so if MOD-001-2 is withdrawn. The MOD standards promote reliability of the grid by putting in place common boundaries and provisions that are necessary for various calculations that need to be performed. These calculations are important to reliability by providing the baseline for understanding the operational need. By retiring the MOD standards, and not having MOD-001-2 in place, there will not be provisions in place to aid an entity in calculating transfer capability. There will not be any boundaries in place for the curtailment of service. We disagree with the commercial based focus that the drafting team took in the technical rationale document. While these MOD standards (and ATC calculation) may have some commercial based elements to them, they also put in place valuable boundaries that help promote consistency in how the industry calculates these values. Removing these boundaries does not promote reliability for the Bulk Electric System and introduces additional burden to the real-time System Operator.

The expectation of the System Operators to ensure the reliability of the BES in the real-time when there have been no requirements to ensure how ATC is calculated or coordinated beyond what is required by NAESB is unrealistic. Some of the most glaring issues with relying solely upon NAESB to regulate the calculation of ATC are: FERC does not have oversight for non-jurisdictional TSPs and therefore cannot require them to incorporate NAESB standards. Also, while NAESB has acted on the recommendations of the MOD-A project to incorporate any of the gaps created by the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and adoption of MOD-001-2, FERC has not acted on either the NERC or NAESB filings. Further, NAESB has not been requested to modify proposed standards to incorporate any of the gaps created by the retirement of the proposed MOD-001-2.

Additionally, the lack of any NERC regulation for consistent ATC methodologies and requirements for sharing of data and could potentially lead to an increase of TLRs being called as this would be the only tool System Operators could utilize to combat rampant loop flow impacts on the BES. This could very well lead to capacity concerns and load shedding as the increase in TLRs could include firm curtailments causing capacity shortages. Without mandatory ATC standards, a TSP would be able to sell as much service as possible. The overselling of service and the overscheduling of ATC Paths will lead to an increase of FIRM TLR, potentially forcing Transmission Operators and Load Serving Entities to shed FIRM load to comply with the TLR. Over the past eight years the MOD-001, 28,29, & 30 standards have been effective the industry has seen a dramatic reduction in FIRM TLRs.

Included in the Attachment with Duke Energy's response to this question is the rolling 12-month average of TLRs from the NERC website. Notice the reduction in TLRs from 2008-2011 when the MOD standards were first published (in 2008 when TSP started to incorporate the MOD standards into their ATC methodologies) and 2011 (when the MOD standards were mandatory and enforceable).


TLRs (total) 12 Month Rolling Average
600
500
400
300
200
100
0
TLRs



Additional comments submitted by ReliabilityFirst

ReliabilityFirst does not agree with the removal of PRC-004-6 Requirement R4 for the following reason:

1. The concept of a declaration for no identifiable cause is currently introduced in R4 and in the Application Guidelines (now called Supplemental Material) for R4. The one statement from the Application Guidelines for R4 in version 5(i) states,
   a. 'The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.'

   This statement needs to be retained somewhere as an explanation for this use of the declaration. The declaration is also referenced in R5, but for a different reason (problem found but CAP won't improve reliability of BES). The declaration associated with R4 would be a cause that is 'unknown/unexplainable' and all testing and analysis comes up empty. There wouldn't be a CAP, since nothing was found broken, and the declaration is used to close the investigation. In MIDAS, the CAP Completion Status would be 'declaration' rather than improperly coding as 'CAP – Complete', since no CAP was developed.

As far as the administrative requirement of ‘corrective action at least once every two calendar quarters’, ReliabilityFirst recommends the following for consideration:

R4:
Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation ~~at least once every two full calendar quarters after the Misoperation was first identified~~, maintaining documentation in sufficient detail to provide clear delineation of the stage and findings of the investigation until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*
☐The identification of the cause(s) of the Misoperation; or
☐A declaration that no cause was identified.

Consideration of Comments

Project Name: 2018-03 Standards Efficiency Review Retirements

Comment Period Start Date: 2/27/2019

Comment Period End Date: 4/12/2019

Associated Ballots: 2018-03 Standards Efficiency Review Retirements FAC-008-4 IN 1 ST; 2018-03 Standards Efficiency Review Retirements FAC-013-2 IN 1 ST; 2018-03 Standards Efficiency Review Retirements INT-004-3.1 IN 1 ST; 2018-03 Standards Efficiency Review Retirements INT-006-5 IN 1 ST; 2018-03 Standards Efficiency Review Retirements INT-009-3 IN 1 ST; 2018-03 Standards Efficiency Review Retirements INT-010-2.1 IN 1 ST; 2018-03 Standards Efficiency Review Retirements IRO-002-6 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-001-1a IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-001-2 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-004-1 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-008-1 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-020-0 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-028-2 IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-029-2a IN 1 ST; 2018-03 Standards Efficiency Review Retirements MOD-030-3 IN 1 ST; 2018-03 Standards Efficiency Review Retirements PRC-004-6 IN 1 ST; 2018-03 Standards Efficiency Review Retirements TOP-001-5 IN 1 ST; 2018-03 Standards Efficiency Review Retirements VAR-001-6 IN 1 ST

There were 49 sets of responses, including comments from approximately 119 different people from approximately 81 companies representing the 10 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 Senior Director of Engineering and Standards Howard Gugel (via email) or at (404) 446-9693.

Questions

1. SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include: BAL-005-1, Requirements R4 and R6; COM-002-4, Requirement R2; EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; IRO-014-3, Requirement R3; IRO-017-1, Requirement R3; and VAR-001-5, Requirement R3. Do you agree with the SDT's recommendation that these standards requirements be considered as part of the SER Phase II effort? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

2. The SDT is proposing to take no action on two standards already scheduled for retirement: PRC-015-1, Requirements R1, R2 and R3; and PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6. Do you agree with the SDT's recommendation to take no action for these standards already scheduled for retirement? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

3. The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit: IRO-002-5, Requirements R4 and R6; IRO-008-2, Requirement R6, and TOP-001-4, Requirements R16 and R17. Do you agree with the SDT's recommendation to retain these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

4. The SDT is proposing to retire FAC-008-3, Requirements R7 and R8. Do you agree with the SDT's proposal to retire these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

5. The SDT is proposing to retire FAC-013-2, Requirements R1, R2, R4, R5 and R6 (all). Do you agree with the SDT's proposal to retire FAC-013-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

6. The SDT is proposing to retire INT-004-3.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-004-3.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

7. The SDT is proposing to retire INT-006-4, Requirements R3.1, R4, and R5. Do you agree with the SDT's proposal to retire Requirements R3.1, R4, and R5 of INT-006-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

8. The SDT is proposing to retire INT-009-2.1, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of INT-009-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

9. The SDT is proposing to retire INT-010-2.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-010-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

10. The SDT is proposing to retire IRO-002-5, Requirement R1. Do you agree with the SDT's proposal to retire Requirement R1 of IRO-002-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

12. The SDT is proposing to retire MOD-008-1, Requirements R1, R2, R3, R4, and R5 (all). Do you agree with the SDT's proposal to retire MOD-008-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

13. **The SDT is proposing to retire MOD-028-2, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, and R11 (all). Do you agree with the SDT's proposal to retire MOD-028-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

14. **The SDT is proposing to retire MOD-029-2a, Requirements R1, R2, R3, R4, R5, R6, R7, and R8 (all). Do you agree with the SDT's proposal to retire MOD-029-2a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

15. **The SDT is proposing to retire MOD-030-3, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9 and R10 (all). Do you agree with the SDT's proposal to retire MOD-030-3? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

16. **The SDT is proposing to retire MOD-001-1a, Requirements R1, R2, R3, R4, R5, R6, R7, R8 and R9 (all). Do you agree with the SDT's proposal to retire MOD-001-1a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

17. **The SDT is proposing to withdraw Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities. Do you agree with the SDT's proposal to withdraw Reliability Standard MOD-001-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

18. **The SDT is proposing to retire MOD-020-0, Requirement R1 (all). Do you agree with the SDT's proposal to retire MOD-020-0? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

19. **The SDT is proposing to retire PRC-004-5(i), Requirement R4. Do you agree with the SDT's proposal to retire Requirement R4 of PRC-004-5(i)? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

20. **The SDT is proposing to retire TOP-001-4, Requirements R19 and R22. Do you agree with the SDT's proposal to retire Requirements R19 and R22 of TOP-001-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

21. **The SDT is proposing to retire VAR-001-5, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of VAR-001-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.**

22. **Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.**

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
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	Tennessee Valley Authority	Kurtz, Bryan G.	Tennessee Valley Authority	1	SERC
					Grant, Ian S.	Tennessee Valley Authority	3	SERC
					Thomas, M. Lee	Tennessee Valley Authority	5	SERC
					Parsons, Marjorie S.	Tennessee Valley Authority	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Brandon Gleason	Electric Reliability	2	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Council of Texas, Inc.		
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC,WECC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Kagen DelRio	North Carolina Electric Membership Cooperative	3,4,5	SERC
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Susan Sosbe	Wabash Valley Power Association	3	SERC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Lee Schuster	Duke Energy	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion, Con-Edison	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick	Kowalczyk	1	NPCC
					John Hastings	National Grid	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. ***SDT has determined that additional work is necessary to ensure the retirement of certain standard requirements does not create a reliability gap. The SDT recommends that these standards requirements be considered as part of the SER Phase II effort. These requirements include: BAL-005-1, Requirements R4 and R6; COM-002-4, Requirement R2; EOP-005-3, Requirement R8; EOP-006-3, Requirement R7; IRO-014-3, Requirement R3; IRO-017-1, Requirement R3; and VAR-001-5, Requirement R3. Do you agree with the SDT's recommendation that these standards requirements be considered as part of the SER Phase II effort? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.***

Summary Response:

The SDT received comments regarding additional retirements from the SAR. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards or requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards to Phase II for further disposition.

The SDT received several comments requesting clarification of the Phase II referrals. The Phase II Standards Efficiency Review created a subteam consisting of the team leadership from Project 2018-03 and two members of the Phase II team. This subteam will, independent of the Phase II concept teams, create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

- BAL-005-1 R4 & R6 are now adequately covered under TOP-010-1(i) and are redundant to list under BAL-005-1

- COM-002-4 R2 should be covered in each entities Systematic Approach to Training per PER-005-2.
- EOP-005-3 R8 should be covered in each entities Systematic Approach to Training per PER-005-2.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.
A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

BAL-005-1 (R4&R6): In order to retire these requirements, TOP-010-1(i) would require modifications to expressly address quality flags addressing missing or invalid data.
COM-002-4: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address COM-002-4 R2.
EOP-005-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-005-3 R8.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment	
GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID determined these requirements the SDT has recommended to be considered as part of the SER Phase II effort should proceed to ballot as proposed retirements based on the original SAR and recommendations from the SER Phase I teams. This would allow the Registered Ballot Body to vote on whether these requirements are appropriate for retirement or if additional work is necessary. If the retirement of	

these requirements do not pass ballot, IID supports that they be considered as part of SER Phase II, however the SDT should ensure the SER Phase II scope clearly indicates they will address requirements. Note that the current SER Phase II scope and six efficiency concepts does not indicate they will be addressing specific requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Regarding BAL-005-1 req.4, Southern Company determined that in order for the BA operators to be able to perform their job effectively, then the BA manager must provide the adequate tools needed that are associated with Reporting ACE. To ensure that the information is correct, the BA manager must ensure that operators have accurate information and have indicators if data is either missing or	

incorrect. Having the current standard only places an administrative burden on BA entities who already have the tools in place and are training their operators on Reporting ACE. Therefore, retiring this requirement would not leave a gap in reliability. In regard to BAL-005-1 req, 6, this is another requirement that poses an administrative burden on BA entities as the calculation of Reporting ACE is critical for any entity to effectively balance load/generation and support interconnection frequency. Again, this is an inherent function of BA entities and retiring this requirement would not leave a gap in reliability. In regard to COM-002-4 req. 2, Southern determined that this requirement could easily be incorporated the current PER-005 standard as it involves System Operator training. Even if the requirement was retired without including it anywhere else in the NERC standards, COM-002-4 R1 would still be enforceable and would require System Operators to follow the documented communication protocols. We don't believe that any additional work is necessary by the SDT as the retirement of this standard would not result in a reliability gap. The related compliance activities in EOP-005-3 R8 can easily be incorporated into the PER-005 standards as a part of an entity's Systematic Approach to Training. System restoration is a reliability-related task and should be included in an entity's training program for its System Operators to ensure that they are and competent to perform restoration activities. The related compliance activities in EOP-006-3 R7 can easily be incorporated into the PER-005 standards as a part of an entity's Systematic Approach to Training. System restoration is a reliability-related task and should be included in an entity's training program for its System Operators to ensure that they are and competent to perform restoration activities. In regard to IRO-014-3 req. 3, this is an inherent part of performing as a Reliability Coordinator as coordination is at the heart of this function. A standard requirement is not needed, because the RC serves an area and has responsibilities for multiple entities. Any improprieties by the RC, will surely be voiced by one or more of the member entities and therefore, a requirement is not needed, and therefore we don't believe that any additional work is necessary by the SDT before retiring this requirement. In regard to VAR-001-5 R3, Monitoring and maintaining voltage/regulating devices is an inherent responsibility of the TOP entity. It is also essential in ensuring effective operations to effectively transfer power while minimizing losses. Furthermore, it is in the TOP entity's best interest to maintain system voltage to avoid overloading the system and causing SOLs and IROLs, along with damage to transmission equipment and facilities. Since these functions are done inherently, the NERC standard only increases the administrative burden on the entities and therefore, retirement of this requirement would not create a gap in reliability.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

BAL-005-1 (R4&R6): In order to retire these requirements, TOP-010-1(i) would require modifications to expressly address quality flags addressing missing or invalid data.
COM-002-4: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address COM-002-4 R2.
EOP-005-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-005-3 R8.
EOP-006-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-006-3 R7
IRO-014-3: IRO-014-3, Requirement R1 time horizon would need to be revised to a time horizon of “Real-time” if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3 is not being sought during this phase of the project.

VAR-001-5: The TOP-series of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary, Requirement R3 is not being sought during this phase of the project.

Please Note: VAR-001-4.2, is an inactive standard. VAR-001-5 changed the WECC variance, and not the continent- wide requirements. VAR-001-5 became effective January 1, 2019.

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	

Comment

In consideration that the actions specified in VAR-001-5 R3 are inherent to the System Operators' core functions, LES determined R3 is still suitable for retirement as part of the SER Phase I effort. The prevention and mitigation of SOL exceedances, as dictated by applicable TOP standards, ensures System Operators utilize the necessary devices to regulate transmission voltage and reactive flow. This requirement provides no additional direction and taken independently is too vague to provide useful guidance in ensuring reliability.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration. VAR-001-5: The TOP-series of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary, Requirement R3 is not being sought during this phase of the project. Please Note: VAR-001-4.2, is an inactive standard. VAR-001-5 changed the WECC variance, and not the continent- wide requirements. VAR-001-5 became effective January 1, 2019.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
If EOP-005-3 R8 is retired, R9 and R10 should be considered at the same time with potential migration into the PER Standards. If EOP-006-3 R7 is retired, R8 should be considered at the same time with potential migration into the PER Standards. Please note that EOP-005-3 and EOP-006-3 are enforceable 04/01/19. If IRO-017-1 R3 is to be retired, A new TPL-001-5 R8 should include the RC function.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the	

reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration. EOP-005-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-005-3 R8. EOP-006-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-006-3 R7.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the retirement of the requirements above in the SER Phase II effort.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	

Answer	Yes
Document Name	
Comment	
Reclamation agrees with the justification for retaining COM-002-4 Requirement R2 and EOP-005-3 Requirement R8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	

LDWP agrees that IRO-017-1 should be a part of a Phase II effort. If the TPL-001-4 standard is not clarified to notify Peak RC of the transmission results then there may not be a mechanism for notifying the RC about potential IROLs.

Likes 0	
Dislikes 0	

Response

Thank you for your support. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	Yes
Document Name	

Comment

Although we agree with moving these Requirements into the SER Phase II effort, there is a concern that addressing these Requirements may be delayed due to the Phase II 'Concept' selection process. Currently the Phase II Concept process has a timeline that extends into September and that date is only for deciding which recommendation(s) to use.

Also, there is no assurance that the Concepts chosen in Phase II will address the deferred Requirements proposed for retirement in Phase I.

A suggestion would be for the Phase II team to address these deferred Requirements separately as they decide on which Concepts to use.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support Edison Electric Institute's response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	

Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that some Reliability Standards and associated requirements present more complex consideration and research in order to ensure proposed retirements do not create unintended reliability gaps. Moreover, we support the proposal to shift such requirements to the SER Phase II effort. However, the recent posting on the SER Phase II Concepts has created some confusion. EEI recommends that NERC or the SER Advisory provide additional information to help clarify the full scope of the upcoming SER Phase II Project—including these requirements for consideration for Phase II and the proposed Concepts. EEI also encourages the SDT to prioritize these requirements for Phase II so that progress is not held up by the SDT efforts to refine the proposed Concepts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.	

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	Yes
Document Name	

Comment

If EOP-005-3 R8 is retired, R9 and R10 should be considered at the same time with potential migration into the PER Standards.

If EOP-006-3 R7 is retired, R8 should be considered at the same time with potential migration into the PER Standards.

Please note that EOP-005-3 and EOP-006-3 are enforceable 04/01/19.

If IRO-017-1 R3 is to be retired, A new TPL-001-5 R8 should include the RC function.

Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

EOP-005-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-005-3 R8.

EOP-006-3: PER-005-2 currently addresses a systematic approach to training, but does not expressly include the identification of a reliability-related task to address EOP-006-3 R7.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	

Comment

In conducting the review, we suggest that where requirements are found to be somewhat, but not completely duplicative, consider proceeding with the retirement of the identified requirements and adding any language of the retired requirement that is still pertinent to the requirements which will still be in effect.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
It appears from the technical rational document that the 2018-03 drafting team determined the Requirements should be revised and retained rather than retired in their entirety. Since standard revision is within the scope of the Phase 2 team, AEP has no objections to the concept of revising COM-002-4 R2, EOP-005-3 R8, IRO-017-1 R3, and VAR-001-5 R3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - sou, Group Name RSC no Dominion, Con-Edison	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

2. The SDT is proposing to take no action on two standards already scheduled for retirement: PRC-015-1, Requirements R1, R2 and R3; and PRC-018-1, Requirements, R1, R2, R3, R4, R5 and R6. Do you agree with the SDT's recommendation to take no action for these standards already scheduled for retirement? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.

Summary Response:

The SDT received comments regarding the retaining of PRC-015-1 and PRC-018-1. The SDT determined that revisions are needed within the PRC-002-2 Implementation Plan in order to pursue immediate retirement of this standard. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement. Therefore, the SDT referred these standards to Phase II for further disposition.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	
PRC-018-1 references Regional Criteria that must be followed to comply with the standard. Duke Energy requests the drafting team consider the ramifications on PRC-018-1 if a Region has already retired its Regional Criteria applicable to PRC-018 and PRC-002. The absence of any applicable Regional Criteria for a particular Region, makes PRC-018-1 a stronger candidate for immediate retirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any	

modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.	

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No
Document Name	

Comment

OKGE disagrees with the SDT's proposal of taking no action on PRC-018-1. Per the PRC-002-2 Implementation Plan,

"Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below."

OKGE determined this justification is flawed. The requirements in PRC-018-1 states that TOs and GOs are required to install DMEs per the requirements established by its Regional Reliability Organization (RRO). However, in the SPP region, since PRC-002-1 was never approved by FERC and with the creation of PRC-002-2, the requirements that were established by SPP on DMEs were removed from SPP Planning Criteria in April 2017. Currently, the SPP RTO has no DME installation requirements, therefore, the entities in the SPP region do not have a set of criteria to follow to meet the requirements in PRC-018-1 (particularly for requirements R4 and R5, where DME equipment required by the RRO is not specified). OKGE determined PRC-018-1 should be retired prior to PRC-002-2's full implementation (i.e 7/1/2022).

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP agrees with the retirement of PRC-015-1 requirements R1, R2, and R3 since they will be superseded by PRC-012.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	

Dislikes 0	
Response	
Please see response to comments from ISO/RTO Council Standards Review Committee.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees that PRC-015-1 and PRC-018-1 should continue on their present scheduled paths toward being retired/superseded.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

3. ***The SDT determined the following requirements are inappropriate for retirement because they serve a reliability benefit: IRO-002-5, Requirements R4 and R6; IRO-008-2, Requirement R6, and TOP-001-4, Requirements R16 and R17. Do you agree with the SDT's recommendation to retain these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation.***

Summary Response:

The SDT received several comments on retaining the requirements in IRO-002-5 (R4 and R6), IRO-008-2 (R6), and TOP-001-4 (R16 and R17). The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards or requirements. Therefore, the SDT referred these standards to Phase II for further disposition.

IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

Requirement R4 of IRO-002-5 needs to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), Internet Technology (IT), or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (cf. IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. In addition, RC equipment outages are not required to follow the RC's outage coordination process (i.e., IRO-017-1, Requirement R2 is only applicable to TOPs and BAs). As such, a potential gap in the standards would exist if IRO-002-5, Requirement R4 was retired.

Although IRO-008-2, Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6 is not being sought during this phase of the project.

The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for

unconditional retirement; i.e. these requirements may be retired without any modifications to other standards or requirements. Therefore, the SDT referred these standards to Phase II for further disposition.
The SDT believes Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

TOP-001-4 R16 and R17 do not provide a reliability benefit. They don't even align with most, if not all, standard business processes. The Outage Coordinator, SCADA EMS, IT Networking, and Communications departments determine the impacts of all "Planned" outages or telemetry equipment. Most System Operators do not even have the technical knowledge to make substantiated decision to delay or postpone this work. Our System Operators may approve "Unplanned" outages but this is a rare exception and is not in scope for these requirements. Other requirements, such as R13 are already in place which demand an extremely high availability of EMS functionality, EMS & IT staff are well aware that unplanned outages impacting the ability to view and solve contingency analysis are unacceptable for anything other than a brief interruption.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP determined the requirements above can be retired without substantive reliability impact consistent with the justifications provided in the SER SAR.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition. A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements. Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS shares the opinion of many others in the industry that the language in requirements TOP-001-4 R16 and R17 does not, in and of themselves, provide any reliability benefit. Simply having "the authority to approve outages and maintenance" does not assure that an approval occurs, nor is it required to be compliant. Since a simple letter or procedure stating that operators have the stated authority is adequate to demonstrate compliance, this action does not provide a reliability benefit.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment

GCPD agrees with the initial assessment that these standards should be retired for the originally-identified rationales.

Likes 0	

Dislikes 0	
Response	

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	

Duke Energy recommends the drafting team consider IRO-008-2 R6 for immediate retirement. We agree with the drafting team's assertion in the Technical Justifications document that characterizes R6 as administrative in nature. We do not believe that there is much if any reliability benefit in requiring an RC to notify the TOPs or BAs of any SOL/IROL exceedance that was prevented or already mitigated. There is already an Operating Plan in place to be followed for such an event, and alerting Operators of an issue that they are already aware of, and potentially distracting them from dealing with other Real-time issues, is of minimal reliability benefit.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments.

The SDT determined that this requirement should be retained for the following reasons:

Although IRO-008-2, Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6 is not being sought during this phase of the project.

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC does not believe that TOP-001-4, Requirements R16 and R17 to "provide its System Operators with the authority to approve outages and maintenance of its telemetering and control equipment…" themselves provide a reliability benefit. Furthermore, we believe that this "authority" is inherent in "acting to maintain the reliability of its TOP/BA Area via its own actions or by issuing Operating Instructions" as is required by TOP-001-4, Requirement R1 and R2, and as such, R16 and R17 are not needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.	

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID determined these requirements the SDT has identified as inappropriate for retirement should proceed to ballot as proposed retirements based on the original SAR and recommendations from the SER Phase I teams. This would allow the Registered Ballot Body to vote on whether these requirements are appropriate for retirement or if additional work is necessary. If the retirement of these requirements do not pass ballot, IID supports that they be considered as part of SER Phase II, however the SDT should ensure the SER Phase II scope clearly indicates they will address requirements. Note that the current SER Phase II scope and six efficiency concepts does not indicate they will be addressing specific requirements.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

In regard to IRO-002-5 R4, it should be retired as approving planned outages is a reliability related task and can be easily incorporated into the current PER-005 standard.   Although the requirement has a benefit to reliability, it should fall within the Operator Training standards. Therefore, the retirement of this standard requirement would be appropriate.

In regard to IRO-002-5 R6, this requirement administrative in nature and duplicative and should be retired based on the following reason/s:

Before an entity is allowed to function as a Reliability Coordinator, it goes through a certification process, which ensures that the entity has all the relative systems in place to perform system monitoring and assessments. In addition, the certification review also involves determining if the entity’s data/voice communication systems have redundancy, the ability to effectively transfer data and has alarms built in to notify System Operators in the event of adverse changes to the system.

Furthermore, the RC function is on a 3-year audit schedule by the RRO and therefore, the RC will have to continuously show that it has these same capabilities.

In regard to IRO-008-2, R6, we see no reliability benefit in this requirement as both the RC and the impacted entities will already have sufficient monitoring systems in place to ensure that all are aware when a potential SOL/IROL has been prevented/mitigated. The specific actions that the RC took to prevent/mitigate the exceedance only benefits reliability from a possible teaching point to System Operators, who may experience the same type of event in the future.

However, from an operational reliability standpoint, there is no benefit to the RC notifying entities of the actions taken to prevent/mitigate and exceedance and takes the RC's attention away from performing its responsibility to continuously monitor and assess the system.

We believe that TOP -001-4 R16 and R17 should be retired as the authority to approve planned outages is a reliability related task that can easily be incorporated into the current PER-005 standard. Although the requirements do benefit reliability, they should fall within the Operator Training standards. Therefore, the retirement of these requirements would be appropriate.

Likes 0	
Dislikes 0	

Response

The SDT determined that IRO-002-5 Requirements R4 and R6 should be retained for the following reasons:

IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

Requirement R4 of IRO-002-5 needs to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), Internet Technology (IT), or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (cf. IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. In addition, RC equipment outages are not required to follow the RC's outage coordination process (i.e., IRO-017-1, Requirement R2 is only applicable to TOPs and BAs). As such, a potential gap in the standards would exist if IRO-002-5, Requirement R4 was retired.

Although IRO-008-2, Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6 is not being sought during this phase of the project.

Thank you for your comments. The SDT determined that additional work (and technical rationale) is needed within standards/requirements prior to retirements on these standards/requirements. The SDT used a risk-based approach to evaluate the reliability benefit of each requirement in the SAR for unconditional retirement; i.e. these requirements may be retired without any modifications to other standards/requirements. For each of the standards addressed herein, the SDT determined that modifications would be necessary to other standards/requirements to maintain reliability. Therefore, the SDT referred these standards/requirements to the SER Phase II effort for further disposition.

A subteam was created consisting of the team leadership from Project 2018-03 Standards Efficiency Review Retirements, and two members of the SER Phase II effort team. This subteam will be independent of the SER Phase II effort concept teams, and will create a SAR to address the standards/requirements they are recommending to move forward for revisions and retirements.

Any comments applicable to the SER Phase II effort, will be referred to the SER Phase II effort subteam for consideration.
The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

ISO-NE recommends to review the retirements of these requirements as part of Phase 2	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP agrees with the SDT's recommendation.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
IRO-002-5 and IRO-008-2 were not reviewed as we are not a RC and therefore the standards are not applicable. Minnesota Power agrees with NSRF's recommendation for TOP-001-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to NSRF comments.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
SRC recommends that the retirement of these requirements be reviewed as part of Phase 2. Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency,	

6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

4. *The SDT is proposing to retire FAC-008-3, Requirements R7 and R8. Do you agree with the SDT's proposal to retire these requirements? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

The SDT received comments regarding the proposed retirement of FAC-008-3 (R7 and R8).

The SDT determined that these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

The identity and rating of the next most limiting equipment is not of value in the Operations Planning Time Horizon relating to these requirements because the elimination of the most limiting equipment cannot occur in the Operations Planning Time Horizon.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

Additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003-3 and should be a separate project.

Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT determined that these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Due to the importance of the use of accurate Facility Ratings in reliable BES operations and planning, Texas RE recommends FAC-008-3 R7 and R8 remain effective in order to emphasize the need to provide accurate Facility Ratings to entities that require Facility Rating data. These Requirements place an emphasis on the provision of accurate Facility Ratings to the entities responsible for the operation and planning of the BES. Although IRO-010 and MOD-032 data specifications will likely address the provision of Facility Ratings to the these entities, the large quantity of additional data potentially included within the data specifications can lead to a reduced emphasis on the Facility Rating component of the data specification. FAC-008-3 R7 and R8 would focus an entity on a specific facet of data and data exchange.

Moreover, FERC Order 693 Paragraph 771 directed NERC to develop modifications to FAC-008-1 to "for each facility, identify the limiting component and, for critical facilities, the resulting increase in rating of that component is no longer limiting". Requirement R8 meets this directive by requiring "Identity of the existing next most limiting equipment of the Facility (R8.1) and "The Thermal Rating for the next most limiting equipment (R8.2).

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT determined that these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

The identity and rating of the next most limiting equipment is not of value in the Operations Planning Time Horizon relating to these requirements because the elimination of the most limiting equipment cannot occur in the Operations Planning Time Horizon.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment	
OPG agrees with RSC position.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments made by RSC.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	No
Document Name	
Comment	
We recommend a separate standards development project be initiated to holistically address issues identified during the periodic review of FAC-008-3 and the potential retirement of FAC-008-3 requirements identified during the Standards Efficiency Review. On March 18, 2010, Docket No. RR09-6-000, FERC issued an order directing NERC to propose modification of electric reliability organization rules of procedure. This order included FERC's concerns regarding facility ratings and limiting elements. (Please see paragraph 13 and 14 of the FERC order.) We believe that additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003 to ensure that most limiting elements are determined. The equipment data that is required to be provided per the other reliability standards may not be sufficient to determine Facility Ratings, including for use in Real Time Models.	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Thank you for your comment. The SDT determined that these requirements should be retired for the following reasons:	

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

The identity and rating of the next most limiting equipment is not of value in the Operations Planning Time Horizon relating to these requirements because the elimination of the most limiting equipment cannot occur in the Operations Planning Time Horizon.

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from ISO/RTO.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

Additional consideration is needed regarding the Facility Ratings requirements and the relationship to the data requirements of MOD-032, IRO-010, and TOP-003-3 and should be a separate project

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT determined that these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The redline version of FAC-008-3 provided by the SDT does not appear to be the same as the version posted on the NERC website under 'Mandatory Standards Subject to Enforcement'. However, the wording of the Requirements proposed for retirement is the same.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT updated the template for this standard during development.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	Yes
Document Name	
Comment	
While we do not oppose the retirement of R7 and R8, we note that some aspects of R8 were added to address a FERC directive in Order 693. The Commission was so intent on this directive that it ordered NERC to modify its Rules of Procedure in a March 18, 2010 Order (Docket No. RR09-6-000) to better accommodate FERC directives in the Standards development process. FERC denied a NERC request for a stay on making further modifications to FAC-008 in September 2010. This ultimately led to development of FAC-008-3 and the addition of R8 under Project 2009-06. FERC approved FAC-008-3 in an order issued on November 17, 2011 (Docket No. RD11-10). The drafting team should consider whether the standards referenced in the technical rationale supporting retirement of R7 and R8 (MOD-032-1, IRO-010-2, and TOP-003-3) adequately address R8, part 8.2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The identity and rating of the next most limiting equipment is not of value in the Operations Planning Time Horizon relating to these requirements because the elimination of the most limiting equipment cannot occur in the Operations Planning Time Horizon.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation supports the retirement of FAC-008-3 Requirements R7 and R8.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

5. *The SDT is proposing to retire FAC-013-2, Requirements R1, R2, R4, R5 and R6 (all). Do you agree with the SDT's proposal to retire FAC-013-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

The SDT received comments regarding the proposed retirement of FAC-013-2. Although assessing transfer capability in the planning horizon is a method to test the robustness of the system, robustness testing of a system is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by FERC in 2014.

TPL-001-5 R1.1.4 takes in to consideration Firm Transmission Service and Interchange and R2.1.3 uses expected transfers. Both FAC-013-2 and TPL-001-5 are for the Near-Term Transmission Planning Horizon. This along with a combination of existing TPL, MOD, and FAC Standards ensures the BES is operated reliably by determining the modelling exists to identify any SOL/IROL(s) and the TOP standards ensure entities prevent or mitigate for any SOL/IROL(s). The purpose is to ensure Bulk Electric System operates reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy would like to reiterate its opposition to the retirement of FAC-013-2.	

An explanation addressing how FERC's concerns in Orders 693 and 729 are still addressed needs to be provided. As stated in introduction with the Whitepaper published with the standard in Project 2010-10:

"Through FERC Orders 693 (paragraphs 782 and 794) and 729 (paragraphs 278, 279, 289, 290 and 291), FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon and communicate the results. In the FERC Order approving the MOD standards related to ATC/AFC calculations (MOD-001, MOD-028, MOD-029, and MOD-030), FERC did not approve NERC's request to withdraw FAC-012-1, nor did they approve the retirement of FAC-013-1. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards.

• The Commission noted that, under FAC-012-1, Reliability Coordinators and Planning Authorities would be required to document the methodology used to establish interregional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon.

• The Commission also noted that, under FAC-013-1, Reliability Coordinators and Planning Authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon.

• The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

• The Commission also noted, that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System.

• The Commission stated that the responsibility for calculation of transfer capabilities in the planning horizon would be appropriately assigned to the Planning Coordinator and not the Reliability Coordinator.

Consistent with the above philosophy and to address FERC's concerns, FAC-013-2 requires that Planning Coordinators have a current documented methodology for use in performing an annual assessment of Transfer Capability in the Near-Term Planning Horizon (Transfer Capability Methodology)."

In the Technical Justification document, the SDT states that:

"The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards."

Assuming that the drafting team is referencing TPL-001 in the above statement, we would like to point out that TPL-001 standard does not REQUIRE that transfer sensitivities be performed and are not likely to indicate limitations to transfer from neighboring systems which is indicative of a neighbor's ability to support a system during an energy emergency. In its response to comments the SDT agreed that at some point in the future it would be appropriate to move the requirements of FAC-013-2 into the TPL standards. This was not possible at the time due to the timing requirements necessary to meet FERC's orders. In addition the SDT's Whitepaper stated:

"The TPL standards define the studies to be performed, the performance requirements for the BES and the details of the required assessments. FAC-013-2 is intended to identify potential future weaknesses in the system by performance of tests - application of bulk energy transfers to stress the system. FAC-013-2 adds to the understanding of system performance obtained through application of the TPL standards, providing knowledge of potential facilities requiring additional focus and analysis."

The Technical Justification document also states that:

"This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities."

We disagree with the coordination reference in the above statement. Coordination occurs through sharing of identified limits to transfer through R2 for awareness and any necessary action.

Next, the Technical Justification document states that:

"Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability."

We disagree with the statement that this is solely related to a market function. Transfers serve to stress test the system in ways that the PC deems best to identify weak points on their system and impacts on their neighbors. The Whitepaper published with the

standard stated, "In addition, this information is not intended in any way to be associated with the granting or denial of transmission service."

"Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments."

While it is true that there is no obligation to use or consider the information in the assessment, as is the case with TPL-001, but the results are required to be shared with neighboring systems. The Whitepaper states "The application of FAC-013-2 will provide an assessment of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. FAC-013-2 addresses FERC's concerns regarding transfer capability in the planning horizon and provides important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES."

"Requirement R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability."

The standard is supposed to provide a stress test as best determined by the PC's operating experience and knowledge to identify future system weaknesses. The Whitepaper states "AC-013-2 allows the Planning Coordinator to develop its Transfer Capability Methodology based on knowledge of its system's sensitivity to transfers and significance of Facilities to reliability, within the framework provided by FAC-013-2." It is not intended to provide information regarding transmission service which is studied in a completely different way.

"Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness."

While there may not be a standard metric for robustness, assessing transfer capability in the planning horizon does add to the PC's portfolio of knowledge of their system's behavior under stressed conditions.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Although assessing transfer capability in the planning horizon is a method to test the robustness of the system, robustness testing of a system is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by FERC in 2014.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) The California ISO has the following additional comment:	

"If FAC-013-2 is retired, then FAC-015 development under Project 2015-09 needs to be revisited, as those activities were premised on FAC-013 continuing to be in effect and modified to FAC-013-3 as part of the comprehensive changes within Project 2015-09."	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from ISO/RTO Council Standards Review Committee. The SDT will communicate with the Project 2015-09 Establish and Communicate System Operating Limits NERC staff to determine if any action needs to be taken in response to your comments.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP determined FAC-013-2 needs further refinement and standardized metrics so that all Planning Coordinators are following a standard methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will communicate with the Project 2015-09 Establish and Communicate System Operating Limits NERC staff to determine if any action needs to be taken in response to your comments.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
It is important to coordinate the retirement of FAC-013-2 with the retirement of FAC-014-2 under NERC Project 2015-09 Establish and Communicate System Operating Limits. The planning level SOLs required under R3, and R4 of FAC-014-2 are usually established based on the FAC-013-2 Transfer Capability Assesment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will communicate with the Project 2015-09 Establish and Communicate System Operating Limits NERC staff to determine if any action needs to be taken in response to your comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes

Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
FAC-013-2 was not reviewed as we are not a PC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

6. *The SDT is proposing to retire INT-004-3.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-004-3.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

The SDT received comments regarding the proposed retirement of INT-004-3.1. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA determined the retirement of the INT-004 requirements should be contingent upon the FERC adoption of the corresponding NAESB standards. NAESB standards do not apply equally to industry participants (e.g., not applicable to non-jurisdictional entities).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
INT-004-3.1 should not be retired until NAESB BPS WEQ-004 version 3.1, 3.2 is approved by FERC concerning Dynamic and Pseudo-Ties schedules.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative

and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees with the proposed retirement of INT-004-3.1. In the Technical Justification document, the drafting team categorizes INT-004-3.1 as more of an impact on transmission costs, rather than reliability. While costs and pricing do not directly impact the reliability aspects of the grid, ensuring levels of transfer and practicing congestion management help to ensure reliability of the grid.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
ACES recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern would support retiring these requirements after they have been reviewed for inclusion into the NAESB WEQ Business Standards and subsequently ratified by FERC.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from NSRF.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative	

and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from ISO/RTO Council Standards Review Committee.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of R3 be contingent upon the implementation of a new NAESB WEQ-004 requirement which necessitates the coordination of Pseudo-ties between impacted entities prior to implementation. This coordination is important for accurate accounting of interchange and ensuring that any related congestion can be properly managed. Without this coordination, the reliability of the system could be impacted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The proposed retirement of INT-004 is due to the fact that Requirements R1 and R2 have not been enforceable for four years now since the Purchasing Selling Entity was deregistered. Those requirements are already largely moved into NAESB and the remaining parts of them are proposed to be moved to NAESB. Since there has been no reliability impact of those requirements not being enforceable for four years, there is no evidence they should be reinstated applicable to a different functional entity. Requirement 3 of INT-004 only requires the registration of data in the NAESB registry for the purpose " to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie." There is now an extensive NERC Pseudo-Tie Coordination Guideline. One of the primary guiding principles of periodic review teams is to determine if requirements are duplicative and whether they have a significant impact on reliability. Since R3 only serves to register Pseudo-Ties in a registry and their coordination is well-documented, it was unanimous there was no reliability benefit to retaining R3.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

7. The SDT is proposing to retire INT-006-4, Requirements R3.1, R4, and R5. Do you agree with the SDT's proposal to retire Requirements R3.1, R4, and R5 of INT-006-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

Summary Response:

The SDT received comments regarding the proposed retirement of INT-006-4 (R3.1, R4 and R5). The requirements in INT-006 (except for R3.1) proposed for retirement are those that are performed by software in accordance with the NAESB e-Tagging specification. There is no operator action occurring. These validation and notifications occur because of their inclusion in the e-Tagging specification. There are many actions that occur because of these specifications. All of them are not included in NERC requirements and yet they all occur. The retirement of these requirements does not take away visibility of the status of interchange as BAs and TSPs can always see the status of an interchange. Therefore, the performance of these requirements does not provide any visibility that isn't otherwise present.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy disagrees with the proposed retirements for INT-006-4. We are not confident that this issue is adequately covered in the NAESB standards. Unlike the NERC standards which aim to promote reliability, the NAESB standards are commercially focused, and are not viewed as essential to maintaining a reliable system. We believe that not having these conditions outlined, could negatively impact reliability.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The requirements in INT-006 (except for R3.1) proposed for retirement are those that are performed by software in accordance with the NAESB e-Tagging specification. There is no operator action occurring. These validation and notifications occur because of their inclusion in the e-Tagging specification. There are many actions that occur because of these specifications. All of them are not included in NERC requirements and yet they all occur. The retirement of these requirements does not take away visibility of the status of interchange as BAs and TSPs can always see the status of an interchange. Therefore, the performance of these requirements does not provide any visibility that isn't otherwise present.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

Disagree, R4, R5 - North American Energy Standards Board (NAESB) e-Tagging specifications is not part of WEQ Business Practice Standards or approved by FERC, this will leave a responsibility gap for compliance.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. If e-Tagging specifications are important for NAESB's purposes, NAESB is empowered to address them in NAESB's business practices. NERC's role is to establish requirements to maintain reliability and e-Tagging specifications are not related to Bulk Electric System reliability. The requirements in INT-006 (except for R3.1) proposed for retirement are those that are performed by software in accordance with the NAESB e-Tagging specification. There is no operator action occurring. These validation and notifications occur because of their inclusion in the e-Tagging specification. There are many actions that occur because of these specifications. All of them are not included in NERC requirements and yet they all occur. The retirement of these requirements does not take away visibility of the status of interchange as BAs and TSPs can always see the status of an interchange. Therefore, the performance of these requirements does not provide any visibility that isn't otherwise present.

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment	
Idaho Power does not agree with retiring the R3.1 and R5 requirements. R3.1: It is important to define how long an entity has to approve or deny interchange. R5: Notification in a timely manner is needed.	
Likes 0	
Dislikes 0	
Response	
The requirements in INT-006 (except for R3.1) proposed for retirement are those that are performed by software in accordance with the NAESB e-Tagging specification. There is no operator action occurring. These validation and notifications occur because of their inclusion in the e-Tagging specification. There are many actions that occur because of these specifications. All of them are not included in NERC requirements and yet they all occur. The retirement of these requirements does not take away visibility of the status of interchange as BAs and TSPs can always see the status of an interchange. Therefore, the performance of these requirements does not provide any visibility that isn't otherwise present.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM supports the partial retirement of these standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	

Likes 0	
Dislikes 0	
Response	
Please see response to the comments from NSRF.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
R3.1 – There is no impact on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. The RC is already notified of a denial via E-tag as required in the NAESB e-Tagging Specifications. R4 & R5 are duplicative of the NAESB e-Tagging Specifications Section and are not a reliability-related task performed by a NERC registered entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

8. ***The SDT is proposing to retire INT-009-2.1, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of INT-009-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

The SDT received comments regarding the reference of INT-010 in Requirement R1 of INT-009-2.1. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot.

The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
The requirement is redundant and qualifies for retirement under Paragraph 81. The requirement for BAs to establish an agreed upon interchange meeting source is covered in BAL-005-1 R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Informationally, Paragraph 81 was adopted by the NERC Board of Trustees on February 7, 2013, filed with the appropriate regulatory authority on February 28, 2013, with a Final Rule issued November 21, 2013.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from NSRF.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	

Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	

Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM supports the partial retirement of these standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

9. *The SDT is proposing to retire INT-010-2.1, Requirements R1, R2, and R3 (all). Do you agree with the SDT's proposal to retire INT-010-2.1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot.

The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE agrees that the specific content of INT-010, creating an RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3 proposed as part of this effort continues to reference INT-010. Therefore, ISO-NE recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot. The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
Although AZPS agrees these requirements can and should be retired, their retirement must be done in coordination with changes to INT-009-2.1 R1, which references INT-010-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot. The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	No
Document Name	
Comment	
NPCC agrees that the specific content of INT-010, creating RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3 proposed as part of this effort continues to reference INT-010, Therefore, NPCC recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Thank you for your comment. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot. The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy disagrees with the drafting team's proposal to retire this standard. The technical rationale document states that this standard can be retired because more stringent tagging requirements already exist under NAESB. Unlike the NERC standards which aim to promote reliability, the NAESB standards are commercially focused, and are not viewed as essential to maintaining a reliable system. While part of INT-010-2.1 may be commercial in nature, we believe that the standard generally supports the reliability of the grid. Also, NAESB is only applicable to jurisdictional entities. Not all entities that are currently NERC Registered Entities, fall under the jurisdiction of NAESB, and would not be required to adhere to any of its business practices.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. While all NERC registered entities may not be subject to NAESB business practices, BAs are expressly applicable under this standard are subject to NAESB business practices.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

Disagree, NAESB WEQ BPS 004-1.7 reference NERC INT-010-2.1 R1 for energy sharing groups for conditions not submitting eTags. Not approved by FERC.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. If e-Tagging specifications are important for NAESB purposes, NAESB is empowered to address them in NAESB's business practices. NERC's role is to establish requirements to maintain reliability and e-Tagging specifications are not related to Bulk Electric System reliability.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with RSC position.	
Likes 0	
Dislikes 0	
Response	
Please see response to comment from RSC.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of the standard be contingent upon a new NAESB WEQ-004 requirement becoming effective which allows interchange fitting the current INT-010-2.1 criteria to be implemented without an RFI. Such a requirement is currently published as WEQ-004-1.7 under the NAESB WEQ version 3.2 standards. However, the WEQ-004-1.7 requirement would need to be revised. Without this NAESB requirement, a Balancing Authority would not be able to implement interchange transactions described in INT-010-2.1 without an associated RFI which could jeopardize the reliability of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. If e-Tagging specifications are important for NAESB's purposes, NAESB is empowered to address them in NAESB's business practices. NERC's role is to establish requirements to maintain reliability and e-Tagging specifications are not related to Bulk Electric System reliability.	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	

Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM recommends that the retirement of the Standard be contingent upon a new NAESB WEQ-004 requirement becoming effective which allows interchange fitting the current INT-010-2.1 criteria to be implemented without an RFI. Such a requirement is currently published as WEQ-004-1.7 under the NAESB WEQ version 3.2 standards. However, the WEQ-004-1.7 requirement would need to be revised. Without this NAESB requirement, a Balancing Authority would not be able to implement interchange transactions described in INT-010-2.1 without an associated RFI which could jeopardize the reliability of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. If e-Tagging specifications are important for NAESB purposes, NAESB is empowered to address them in NAESB's business practices. NERC's role is to establish requirements to maintain reliability and e-Tagging specifications are not related to Bulk Electric System reliability.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power agrees with NSRF's recommendation.	
Likes 0	
Dislikes 0	
Response	

Please see response to the comments from NSRF.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	Yes
Document Name	

Comment

The SRC agrees that the specific content of INT-010, creating an RFI or Reliability Adjusted Arranged Interchange after-the-fact, does not impact reliability. However, if INT-010 is to be retired, then INT-009 R1 must also be modified and that revision is not addressed in the Implementation Plan. INT-009-3 proposed as part of this effort continues to reference INT-010. Therefore, the SRC recommends that either INT-009 R1 be modified to simply remove the cross reference to INT-010 or that the retirement of INT-010 and corresponding changes required INT-009 R1 be moved to Phase 2 of this effort.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot.

The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment	
R1, R2 and R3 are redundant because more stringent requirement(s) that meet the objectives are already included in the NAESB standards (WEQ-004-1 & WEQ-004-8) due to their commercial purposes. These requirements do little, if anything, to benefit or protect the reliable operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements. However, because INT-009-2.1 Requirement R1 refers to INT-010-2, it may be preferable to defer consideration to the retirement of the requirements in INT-010-2.1 to the SER Phase II effort.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot. The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of the Requirement and	

that no further changes to this Requirement are necessary. This determination has been vetted by NERC staff and the Standards Committee and it was determined to be a non-substantive change.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

10. ***The SDT is proposing to retire IRO-002-5, Requirement R1. Do you agree with the SDT's proposal to retire Requirement R1 of IRO-002-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

The SDT received comments regarding the proposed retirement of IRO-002-5 (R1). Requirement R1 and data exchange for the Operation Planning Analysis is inherent to Requirement R2 that actually has a higher Violation Risk Factor and is clearly tied to the Operation Planning Analysis in IRO-010-2, Requirement R3. The requirements in IRO-010-2 satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis, Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via redundant/secure communications, such as: Inter Control Center Communication Protocol (ICCP), email, voltage schedules, outage scheduling that all RCs, Bas, and TOPs use to exchange the required data. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the Operation Planning Analysis. Finally, Measure M1 for IRO-002-5, Requirement R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the SDT determined that IRO-002-5, Requirement R1 is not needed to support reliability and can be retired.

Please note:

Proposed Reliability Standard IRO-002-7 reflects a change of version (during initial posting under this project it was posted as IRO-002-6) due to the addition of a new Variance for the WECC region, developed through the WECC standard development process and was adopted by the WECC Board of Directors on March 6, 2019.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	

We believe the other requirements of IRO-002-5 are fundamentally based upon R1, as this requirement mandates RCs to have data exchange capabilities. Other requirements in this standard refer to this term periodically. As such, eliminating this requirement would diminish clarity regarding expectations in the remaining requirements. If R1 is retired it could be merged with R2 so that there is a single requirement discussing all data exchange capabilities needed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Requirement R1 and data exchange for the Operation Planning Analysis is inherent to Requirement R2 that actually has a higher Violation Risk Factor and is clearly tied to the Operation Planning Analysis in IRO-010-2, Requirement R3. The requirements in IRO-010-2 satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis, Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via redundant/secure communications, such as: Inter Control Center Communication Protocol (ICCP), email, File Transfer Protocol (FTP), outage scheduling tools that all RCs, BAs, and TOPs use to exchange the required data. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the Operation Planning Analysis. Finally, Measure M1 for IRO-002-5, Requirement R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the SDT determined that IRO-002-5, Requirement R1 is not needed to support reliability and can be retired.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned that if IRO-002-5 Requirement R1 was eliminated, Reliability Coordinators may not put emphasis specifically on having data exchange capabilities with their Balancing Authorities and Transmission Operators. This could also lead to a larger engagement scope and the inclusion of IRO-008-2 R1, and IRO-010-2 Requirements R1, R2, and R3, instead of just including IRO-002-5 Requirement R1.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R1 and data exchange for the Operation Planning Analysis is inherent to Requirement R2 that actually has a higher Violation Risk Factor and is clearly tied to the Operation Planning Analysis in IRO-010-2, Requirement R3. The requirements in IRO-010-2 satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis, Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via redundant/secure communications, such as: Inter Control Center Communication Protocol (ICCP), email, File Transfer Protocol (FTP), outage scheduling tools that all RCs, BAs, and TOPs use to exchange the required data. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the Operation Planning Analysis. Finally, Measure M1 for IRO-002-5, Requirement R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the SDT determined that IRO-002-5, Requirement R1 is not needed to support reliability and can be retired.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Southern determined that this requirement should be retired as it does not add any additional benefit to reliability. Before an entity is certified to perform the RC function, it must first demonstrate that it has adequate communications (both data and voice) to communicate with BAs and TOPs in its RC area and with those entities adjacent to its RC area. In addition, the RC function is on a 3 year audit cycle and must continue to demonstrate that it has those communication capabilities to remain certified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	

Comment	
IRO-002-5 was not reviewed as we are not a RC and therefore the standard is not applicable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

11. *The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC Standards of Conduct (SOC) violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	Attach_DE_SER Question 11_Apr 2019.docx

Comment

While Duke Energy would support the retirement of these MOD standards, we cannot do so if MOD-001-2 is withdrawn. The MOD standards promote reliability of the grid by putting in place common boundaries and provisions that are necessary for various calculations that need to be performed. These calculations are important to reliability by providing the baseline for understanding the operational need. By retiring the MOD standards, and not having MOD-001-2 in place, there will not be provisions in place to aid an

entity in calculating transfer capability. There will not be any boundaries in place for the curtailment of service. We disagree with the commercial based focus that the drafting team took in the technical rationale document. While these MOD standards (and ATC calculation) may have some commercial based elements to them, they also put in place valuable boundaries that help promote consistency in how the industry calculates these values. Removing these boundaries does not promote reliability for the Bulk Electric System and introduces additional burden to the real-time System Operator.

The expectation of the System Operators to ensure the reliability of the BES in the real-time when there have been no requirements to ensure how ATC is calculated or coordinated beyond what is required by NAESB is unrealistic. Some of the most glaring issues with relying solely upon NAESB to regulate the calculation of ATC are: FERC does not have oversight for non-jurisdictional TSPs and therefore cannot require them to incorporate NAESB standards. Also, while NAESB has acted on the recommendations of the MOD-A project to incorporate any of the gaps created by the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and adoption of MOD-001-2, FERC has not acted on either the NERC or NAESB filings. Further, NAESB has not been requested to modify proposed standards to incorporate any of the gaps created by the retirement of the proposed MOD-001-2.

Additionally, the lack of any NERC regulation for consistent ATC methodologies and requirements for sharing of data and could potentially lead to an increase of TLRs being called as this would be the only tool System Operators could utilize to combat rampant loop flow impacts on the BES. This could very well lead to capacity concerns and load shedding as the increase in TLRs could include firm curtailments causing capacity shortages. Without mandatory ATC standards, a TSP would be able to sell as much service as possible. The overselling of service and the overscheduling of ATC Paths will lead to an increase of FIRM TLR, potentially forcing Transmission Operators and Load Serving Entities to shed FIRM load to comply with the TLR. Over the past eight years the MOD-001, 28,29, & 30 standards have been effective the industry has seen a dramatic reduction in FIRM TLRs.

Included in the Attachment with Duke Energy’s response to this question is the rolling 12-month average of TLRs from the NERC website. Notice the reduction in TLRs from 2008-2011 when the MOD standards were first published (in 2008 when TSP started to incorporate the MOD standards into their ATC methodologies) and 2011 (when the MOD standards were mandatory and enforceable).

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC Standards of Conduct (SOC) violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those

submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts: Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions. Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. **Requirement R6:** If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	
Response	
Please see response to comment in Question 17.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

12. *The SDT is proposing to retire MOD-008-1, Requirements R1, R2, R3, R4, and R5 (all). Do you agree with the SDT's proposal to retire MOD-008-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are

mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators.

However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is

explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for “Other SOLs.”

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as “The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider’s system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.”

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	

TVA disagrees with the retirement of these standards at this time.

Until a resolution is reached on NAESB's WEQ-023, and these items are incorporated by reference per the FERC Commission, retirement of these MOD Reliability Standards would leave a significant gap of reliability of ATC in the industry. WEQ-023 (submitted under Version 003.1) was not approved by the Commission to be incorporated by reference at this time and is being considered under an overall inquiry into ATC calculation. This leaves the standard, as written in NAESB as voluntary. MOD-001-2 was drafted with the mindset of leaving only reliability aspects of ATC under NERC oversight and WEQ-023 being approved by the Commission. If MOD-001-2 is withdrawn, there would be no reliability push for ATC requirements under FERC and could potentially cause further delay. Removal of these standards could impact the transparency that is established with sharing data with neighbors as well.

According to Project 2012-05 ATC Revisions (MOD A), MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

The WEQ-023 standards drafted did not incorporate honoring neighboring systems nor ensure an entity have an ATCID, or TRMID, or CBMID because the thought was that it would be laid out in the NERC space under MOD-001-2. So NAESB would have to incorporate all of this into the business practice, which would blur the lines of reliability and commercial that the project was developed to address.

TVA agrees with the goal of the Standards Efficiency Review Team to decrease the number of requirements and make the standards less confusing and less burdensome. Yet, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and

ignoring the impact on your system, this too will affect your reliability. This does not just impact transmission costs as some would believe.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as “The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider’s system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.”

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Please see response to comment in Question 11.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

13. ***The SDT is proposing to retire MOD-028-2, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, and R11 (all). Do you agree with the SDT's proposal to retire MOD-028-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*****.**

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response	
Please see response to comment in Question 11.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators. However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators	

must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. **Requirement R6:** If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NAESB WEQ-023 document is out of scope for this SDT.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	
Response	
Please see response to comment in Question 17.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see responses to comments submitted by Edison Electric Institute.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	
Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.

Likes 0	
Dislikes 0	

Response
Thank you for your comment.

14. ***The SDT is proposing to retire MOD-029-2a, Requirements R1, R2, R3, R4, R5, R6, R7, and R8 (all). Do you agree with the SDT's proposal to retire MOD-029-2a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*****.**

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are

mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators. However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules." **MOD-001-2:** **Requirement R1:** TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is	

explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for “Other SOLs.”

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as “The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider’s system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.”

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No

Document Name	
Comment	
See response to question 11.	
Likes 0	
Dislikes 0	
Response	
Please see response to comment in Question 11.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The current standard addresses aspects that are commercial in nature. The reliability assessment requirement for determining transfer limits is addressed in FAC-11	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
LDWP agrees that this standard no longer directly impacts system reliability. However, there should be a standardization of TTC/ATC calculation so that there is uniformity between entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	

Response	
Please see response to comment in Question 17.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

15. ***The SDT is proposing to retire MOD-030-3, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9 and R10 (all). Do you agree with the SDT's proposal to retire MOD-030-3? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	

See response to question 11.

Likes 0	
Dislikes 0	

Response	
Please see response to comments in Question 11.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	

TVA disagrees with the retirement of these standards at this time.

Until a resolution is reached on NAESB's WEQ-023, and these items are incorporated by reference per the FERC Commission, retirement of these MOD Reliability Standards would leave a significant gap of reliability of ATC in the industry. WEQ-023 (submitted under Version 003.1) was not approved by the Commission to be incorporated by reference at this time and is being considered under an overall inquiry into ATC calculation. This leaves the standard, as written in NAESB as voluntary. MOD-001-2 was drafted with the mindset of leaving only reliability aspects of ATC under NERC oversight and WEQ-023 being approved by the Commission. If MOD-001-2 is withdrawn, there would be no reliability push for ATC requirements under FERC and could potentially cause further delay. Removal of these standards could impact the transparency that is established with sharing data with neighbors as well.

According to Project 2012-05 ATC Revisions (MOD A), MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

The WEQ-023 standards drafted did not incorporate honoring neighboring systems nor ensure an entity have an ATCID, or TRMID, or CBMID because the thought was that it would be laid out in the NERC space under MOD-001-2. So NAESB would have to incorporate all of this into the business practice, which would blur the lines of reliability and commercial that the project was developed to address.

TVA agrees with the goal of the Standards Efficiency Review Team to decrease the number of requirements and make the standards less confusing and less burdensome. Yet, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned

into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and ignoring the impact on your system, this too will affect your reliability. This does not just impact transmission costs as some would believe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules." **MOD-001-2:** **Requirement R1:** TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.	

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty. **Requirement R5** and its Requirement Parts: Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions. Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. **Requirement R6:** If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators. However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."	

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	

Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from ISO/RTO Council Standards Review Committee.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments submitted by Edison Electric Institute.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Not applicable to the IESO	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

16. ***The SDT is proposing to retire MOD-001-1a, Requirements R1, R2, R3, R4, R5, R6, R7, R8 and R9 (all). Do you agree with the SDT's proposal to retire MOD-001-1a? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*****.**

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as “The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider’s system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.”

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern continues to disagree with the SER Team's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. Simply stating that ATC/AFC calculations are primarily commercially-focused elements and that there are

mechanisms in place to address reliability in real time is an oversimplification of the ATC/AFC concept. Inaccurately modeling and assessing transfer capability which considers real physical transmission limits on both the host and neighboring systems can create extremely complicated situations in real-time that can unduly burden system operators. However, since FERC has not yet approved MOD-001-2 and has yet to take action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those existing NERC standards. The objective is to have MOD-001-2 in place at the same time as those submitted to FERC by NAESB. Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules." **MOD-001-2:** **Requirement R1:** TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is	

explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method. Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative. **Requirement R4:** The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty. **Requirement R5** and its Requirement Parts: Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions. Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. **Requirement R6:** If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No

Document Name	
Comment	
See response to question 11.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments in Question 11.	
Chris Wagner - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
MOD001 requires that all registered TOPs establish reliability boundaries in which the TSPs can operate to maximize energy business transactions. By moving MOD-001 from under NERC responsibility, the BES reliability may be compromised. Transfer capability includes the impact on other areas due to the transfer of electric power.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated:	

"NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	

Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
MOD-001-1a allows Transmission Operators to select, on the record, the methodology for computing the Available Transfer Capability in a standardized manner, which is the foundation for establishing the quantity of transmission capacity, in excess of native load needs and existing commitments, that may be sold to wholesale transmission customers in a fair and transparent fashion via Open Access Same-Time Information System (OASIS). Absent MOD-001-1a or its successor that meets the same objective, Transmission Operators may be at liberty to craft methodology to calculate ATC that may not be in alignment with the industry. This condition, if it prevails, will lead to unfair practice wherein some Transmission Operator may be held to a higher standard while others will be held to a lower standard. This, in turn, creates a less transparent environment for transmission customers to assess how Transmission Operators derive ATC.	

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-

2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	
Comment	
See response to Q17.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments in Question 17.	

Richard Vine - California ISO - 2

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains	

Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

17. *The SDT is proposing to withdraw Reliability Standard, MOD-001-2, which is currently pending approval by applicable governmental authorities. Do you agree with the SDT's proposal to withdraw Reliability Standard MOD-001-2? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Chris Wagner - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Recommend that the revised MOD-001-2 move forward as the current in force MOD-001 standard.	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules." **MOD-001-2:** **Requirement R1:** TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against. Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs." Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9. Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs. Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See response to question 11.

Likes 0	
Dislikes 0	

Response

Please see response to comments in Question 11.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No

Document Name	
Comment	
NERC petitioned FERC for approval of MOD-001-2 in February 2014. The implementation plan called for the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2. In the petition, NERC characterized the purpose of MOD-001-2 as helping to "ensure that determinations of ATC and AFC are accomplished in a manner that supports the reliable operation of the Bulk Power System." MOD-001-2 was developed under NERC's standard development process and was adopted by the NERC Board of Trustees. Now, five plus years after the petition was filed, and with no publicly visible action by FERC on the petition beyond a NOPR issued in June 2014, the SER drafting team is suggesting the petition for MOD-001-2 be withdrawn. It's not clear how the Real-time operators monitoring of SOLs and IROLs helps ensure that determinations of ATC and AFC are accomplished in a manner that supports the reliable operation of the Bulk Power System. If there are no standards addressing the determinations of ATC and AFC, you can expect that Real-time operators will be dealing with more SOLs and IROLs in the future.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."	

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern continues to disagree with the SDT's proposed petition for the withdrawal of MOD-001-2. Again, we believe that the combined effect of enacting MOD-001-2 while migrating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 MOD into the NAESB standards would strike an appropriate balance of addressing reliability related concerns, while incorporating any market related issues. However, since FERC has not yet approved MOD-001-2 nor has not yet taken any action on incorporating MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a and MOD-030-3 and NAESB's WEQ-23 into the current NAESB standards, Southern Company recommends delaying the retirement of those standards until they are subsequently approved by the Commission (FERC). Once approved by the Commission, the industry should have adequate time to ensure a seamless transition to the new construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a	

functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very

well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Comment as long as all MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 are retired together.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	

Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from ISO/RTO Council Standards Review Committee.	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
MOD-001-1a allows Transmission Operators to select, on the record, the methodology for computing the Available Transfer Capability in a standardized manner, which is the foundation for establishing the quantity of transmission capacity, in excess of native load needs and existing commitments, that may be sold to wholesale transmission customers in a fair and transparent fashion via Open Access Same-Time Information System (OASIS). Absent MOD-001-1a or its successor that meets the same objective, Transmission Operators may be at liberty to craft methodology to calculate ATC that may not be in alignment with the industry. This condition, if it prevails, will lead to unfair practice wherein some Transmission Operator may be held to a higher standard while others	

will be held to a lower standard. This, in turn, creates a less transparent environment for transmission customers to assess how Transmission Operators derive ATC.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments submitted by Edison Electric Institute.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

18. ***The SDT is proposing to retire MOD-020-0, Requirement R1 (all). Do you agree with the SDT's proposal to retire MOD-020-0? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty.

Requirement R5 and its Requirement Parts:
Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions.

Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation.

Requirement R6: If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	

Comment

Although ACES agrees with the retirement of this Standard, the technical justifications for retirement of requirement 1 requires additional clarification as it creates confusions. More specifically, SAR suggests a different justification than what was provided in slides versus slide 17 from the Industry Webinar which was held on 3/21/19 Outreach Webinar.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT drafted additional justifications for MOD-020-0 during the development of the project, subsequent to the SAR approval.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	

Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Duplicative of data provision requirements in MOD-031-2 and IRO-010-2 standards	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	

Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM was heavily involved in the MOD-001-2 and NAESB WEQ-023 development efforts. PJM is neutral on the proposed retirement of MOD-001-2 but supports the position of the SER for the existing MOD standards as reliability components of congestion management are handled amongst eastern interconnect parties through various established coordination processes. PJM cautions against additional revisions to the NAESB WEQ-023 document, especially those driven by issues unique to particular seams or between specific entities, as those issues may not be realized by other parties. Therefore, blanket revisions may unnecessarily impact reliability and/or market aspects for other entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

19. ***The SDT is proposing to retire PRC-004-5(i), Requirement R4. Do you agree with the SDT's proposal to retire Requirement R4 of PRC-004-5(i)? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

The SDT received comments stating that the retirement of PRC-004-5(i) Requirement R4 could potentially burden the entity with an open item, with no closing date, hoping that a new technological break-through will finally determine the cause of misoperation. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions subject the quarterly data to a peer review of submittals, which then has the opportunity to further question the entity if needed.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison

Answer	No
Document Name	

Comment

The retirement of PRC-004-5(i) could potentially burden the entity with an open item, with no closing date, hoping that a new technological break-through will finally determine the cause of misoperation. We believe entities will simply declare that no cause for the misoperation was identified and be done with it.

If R4 is retired, one or both of the following approaches will likely be taken by entities:

· Delaying formal declaration of a misoperation for all disturbances until the root cause is identified or until 120 days expires.

· Declaring the cause for a greater percentage of misoperations as "unknown" and not performing the detailed testing to find the true root cause for an issue that is intermittent.

This is not beneficial to the goal of reliability improvements and reduced misoperations.

We recommend that the SDT consider how the ability to declare that "no cause of a misoperation was identified" be retained within the standard to document the end of an investigation. We are concerned that the removal of the ability to declare that no cause of a misoperation was identified may result in audit and compliance concerns.	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
If R4 is retired, one or both of the following approaches will likely be taken by entities: • Delaying formal declaration of a misoperation for all disturbances until the root cause is identified or until 120 days expires. • Declaring the cause for a greater percentage of misoperations as "unknown" and not performing the detailed testing to find the true root cause for an issue that is intermittent. This is not beneficial to the goal of reliability improvements and reduced misoperations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with RSC position.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments by RSC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned that eliminating a requirement to investigate and track Misoperations could lead to entities not investigating the cause of a Misoperation. The SDT states the Requirement R4 acts as a control to support Requirements R1 and R3. Requirements R1 and R3 are different though, in that they are in place to determine *whether or not a Misoperation occurred*. Requirement R4 is to determine the *cause* of the Misoperation. Understanding the cause of a Misoperation can help prevent Misoperations in the future. Indeterminate causes of Misoperations are difficult issues that can provide valuable lessons for all entities involved in system protection. Protection System Misoperations continue to be a significant reliability risk factor and exacerbate the impact of transmission outages. In the 2017 State of Reliability Report, 9% of the Misoperations were categorized as “Unknown/Unexplainable”. The 2018 State of Reliability Report noted that “Protection system Misoperation should remain an area of focus, as it continues to be one of the largest contributors to the severity of transmission outages.” The 2018 State of Reliability report shows no decline in the percentage (9%) which is indicative that more focus is needed. Tracking the issues, if actively pursued, may help entities across the ERO understand complex	

issues when the cause of a Misoperation is identified. Removal of this Requirement disincentivizes an entity in continuing to find Misoperation causes which then, if found, be used to improve reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT does not support the outright retirement of PRC-004-5(i), Requirement R4 because to do so would eliminate the requirement to investigate in its entirety. However, ERCOT agrees that the Requirement as written may impose unnecessary burden by requiring repeated investigations despite the potential inability of a Transmission Owner, Generator Owner, or Distribution Provider to identify the cause(s) of a Misoperation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No

Document Name	Project 2018-03 PRC-004-6 R4 Comments.docx
Comment	

ReliabilityFirst does not agree with the removal of PRC-004-6 Requirement R4 for the following reason:

The concept of a declaration for no identifiable cause is currently introduced in R4 and in the Application Guidelines (now called Supplemental Material) for R4. The one statement from the Application Guidelines for R4 in version 5(i) states,

‘The entity’s investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.’

This statement needs to be retained somewhere as an explanation for this use of the declaration. The declaration is also referenced in R5, but for a different reason (problem found but CAP won’t improve reliability of BES). The declaration associated with R4 would be a cause that is ‘unknown/unexplainable’ and all testing and analysis comes up empty. There wouldn’t be a CAP, since nothing was found broken, and the declaration is used to close the investigation. In MIDAS, the CAP Completion Status would be ‘declaration’ rather than improperly coding as ‘CAP – Complete’, since no CAP was developed.

As far as the administrative requirement of ‘corrective action at least once every two calendar quarters’, ReliabilityFirst recommends the following for consideration (see attached as well for redline of requirment):

R4:

Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation [maintaining documentation in sufficient detail to provide clear delineation of the stage and findings of the investigation] until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*

☐ The identification of the cause(s) of the Misoperation; or

☐ A declaration that no cause was identified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not agree that PRC-004-5(i) R4 meets the drafting team's "Evaluation Criteria for Retiring Reliability Standards Requirements", as the declaration of "no cause found" is made only within this obligation (i.e. "is not redundant"). Regarding the reliability rationale, we would agree that not all investigative actions in and of themselves improve reliability, however the ability to track investigative actions over an extended period of time ensures more rigor is applied to the investigative progress.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes

Document Name	
Comment	
NA to ISO-NE and repeated attempts to determine a cause of relay misoperations as described by R4 don't appear to be productive.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Reclamation supports the retirement of PRC-004-5(i) Requirement R4. Reclamation recommends PRC-004-5(i) Requirement R5 be split into two requirements: one to develop a corrective action plan or explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken; and one to evaluate the corrective action plan for applicability to the entity's other Protection Systems including other locations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. PRC-004-5(i) Requirement R5 is out of the scope of this project.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
we are concerned that simply retiring this requirement could create some unintended negative consequences. As it is well understood, not all misoperations can be definitively determined no matter how detailed or thorough the investigation. It is for this reason that earlier SDTs included in Requirement R4 the ability to declare that no cause could be determine as part of the Misoperation Identification and Correction process. It is also noteworthy to mention that Requirement R4 is the only requirement within this standard that allows such a declaration. Therefore, care will be needed when retiring Requirement R4 to ensure that language is added to the standard to ensure this important ability and right held by TOs, GOs and DPs is not lost. To better understand this concern, EEI suggests that a thorough review of the flowchart (see R4) on Page 36 of PRC-004-5(i) is conducted by the responsible SDT."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submitthe quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees that the investigative actions conducted for Misoperations do not directly improve BES reliability, and thus Requirement R4 should be retired. However, Entities are still required to provide quarterly reports to MIDAS on misoperation types and causes, thus investigation is still a necessary part of this Standard. So, to capture this supplemental administrative requirement, NV Energy would recommend the SDT to modify R5 to include a situation where the cause of the Misoperations is unknown, which ais an allowable entry for cause in MIDAS. We don't think it is clear that the unknown cause can be described in the current language in R5. It is still unclear if an R5 declaration within a CAP that the actions are beyond the entities control can be tied to an "unknown" cause. Given that the R5 "60-day time requirement" starts when the cause is identified, but if the cause is unknown, when does that clock start?. If the	

current wording in R5 remains intact, entities can technically stop at R3 for Misoperations that it has not identified a cause. We do not believe that this is the intent of the standard. If this clarity is not provided, there is a potential that when auditing the Requirement, one can determine that a cause must be identified, if there is no clear requirement that allows a cause of "unknown" to be declared.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Requirement R5 is out of scope of this project. Please see the redline version of the standard's flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
Avista concurs with EEI comments: “EEI supports the retirement of PRC-004-5(i), Requirement R4; however, we are concerned that simply retiring this requirement could create some unintended negative consequences. As it is well understood, not all misoperations can be definitively determined no matter how detailed or thorough the investigation. It is for this reason that earlier SDTs included in Requirement R4 the ability to declare that no cause could be determined as part of the Misoperation Identification and Correction process. It is also noteworthy to mention that Requirement R4 is the only requirement within this standard that allows such a declaration. Therefore, care will be needed when retiring Requirement R4 to ensure that language is added to the standard to ensure this important ability and right held by TOs, GOs and DPs is not lost. To better understand this concern, EEI suggests that a thorough review of the flowchart (see R4) on Page 36 of PRC-004-5(i) is conducted by the responsible SDT.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submit the quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Please see the redline version of the standard’s flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Please see response to the comments from Edison Electric Institute.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: ERCOT has not signed on to this SRC joint response, however will provide its own response in a separate submission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Allie Gavin - Allie Gavin On Behalf of: James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	

Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	

MEC agrees with the SDT that investigative actions for Misoperations do not improve reliability. Therefore, we are prepared to support the SDT's draft revision to retire R4.

We would also like the drafting team to modify R5 to include a situation where the cause of the Misoperations is unknown. We don't believe it is clear that the unknown cause can be described in the R5 declaration that the CAP is beyond the entities control. The R5 60 day time requirement starts when the cause is identified. How do you start the clock to develop the CAP if the cause is unknown? The R5 declaration is after this time requirement in the standard. If the current wording in R5 remains intact, entities can technically stop at R3 for Misoperations that it has not identified a cause. I do not think this is the intent of the standard.

Another issue is that an auditor can determine that a cause must be identified if there is no clear requirement that allows a cause known declaration. There are some Misoperations (very few) where the Protection Engineer will not be able to determine a cause. The is why MIDAS has a cause unknown option.

See the PRC-004-5i flowchart and how you jump from R3 to R5 if R4 is removed.

Likes 1	Berkshire Hathaway Energy - MidAmerican Energy Co., 1, Harbour Terry
Dislikes 0	

Response

Thank you for your comments. PRC-004 is subject to a quarterly NERC Rules of Procedure Section 1600 data submittal. All regions submitthe quarterly data to a peer review group, which then has the opportunity to further question the entity if needed. Requirement R5 is out of scope for this project.

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, 6

- On Page 23 of 32 of the posted, proposed "clean" version of PRC-004-6, the sentence:

"Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins."

This sentence references the required actions in Requirement R4 of the Standard, which is to be retired. Recommend this sentence be deleted.

- On Page 24 of 32 of the posted, proposed "clean" version of PRC-004-6, in the second to the last paragraph, the phrase "under Requirement R4". Recommend this phrase be deleted.

• On Page 32 of 32 of the posted, proposed “clean” version of PRC-004-6, in the Flowchart, the area of the Flowchart leading into R5, the box labeled “Cause Known?” has only a path into R5. The Standard must still provide the option to end an investigation with no cause found. Recommend: • For a Misoperation with no cause found, the flowchart should also point from “Cause Unknown?” to the “Stop” circle to the left. • Add “Yes” to the existing path from “Cause Unknown?” to R5, and “No” to the new path to “Stop”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has updated the standard based on comments received. Please see the redline version of the standard’s flowchart on the project page that demonstrates how an entity proceeds from R3 to R5.	

20. ***The SDT is proposing to retire TOP-001-4, Requirements R19 and R22. Do you agree with the SDT's proposal to retire Requirements R19 and R22 of TOP-001-4? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

The SDT received comments indicating concern that if TOP-001-4, Requirements R19 and R22 were retired, Transmission Operators may not put emphasis specifically on having data exchange capabilities with the entities they have identified it needs data from to perform its Operational Planning Analyses and that Balancing Authorities may not put emphasis specifically on having data exchange capabilities with the entities it has identified it needs data from to perform its Operating Plan for next-day operations. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22 for the Operation Planning Analysis are inherent to Requirement R20 and R23 that actually has a higher Violation Risk Factor and is clearly tied to the Operation Planning Analysis in TOP-003-3 Requirements R1, R2, R3, R4 and R5. The data exchange capabilities are indicated in TOP-003-3, Requirement R1, R2, R3, R4, R5, which includes BAs and TOPs and TOP-002-4, Requirements R1, R2 and R4 to perform the OPA, which makes TOP-001-4 R19 and R22 redundant with the aforementioned standards and requirements. The purpose statement of TOP-003-3 is "To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities". The purpose statement of TOP-002-4 is "To ensure that transmission Operators and Balancing Authorities have plans for operating within specified limits" using the data collected per TOP-003-3 and ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The requirements in TOP-001-4 satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via a redundant/secure Inter Control Center Communication Protocol (ICCP) that all RC's, BA's TOP's use to exchange the required data.

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

Texas RE is concerned that if TOP-001-4 Requirements R19 was eliminated, Transmission Operators may not put emphasis specifically on having data exchange capabilities with the entities they have identified it needs data from to perform its Operational Planning Analyses . Texas RE is concerned that if TOP-001-4 Requirements R22 was eliminated, Balancing Authorities may not put emphasis specifically on having data exchange capabilities with the entities it has identified it needs data from to perform its Operating Plan for next-day operations .	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22 for the Operation Planning Analysis are inherent to Requirement R20 and R23 that actually has a higher Violation Risk Factor and is clearly tied to the Operation Planning Analysis in TOP-003-3 Requirements R1, R2, R3, R4 and R5. The data exchange capabilities are indicated in TOP-003-3, Requirement R1, R2, R3, R4, R5, which includes BAs and TOPs and TOP-002-4, Requirements R1, R2 and R4 to perform the OPA, which makes TOP-001-4 R19 and R22 redundant with the aforementioned standards and requirements. The purpose statement of TOP-003-3 is "To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities". The purpose statement of TOP-002-4 is "To ensure that transmission Operators and Balancing Authorities have plans for operating within specified limits" using the data collected per TOP-003-3 and ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The requirements in TOP-001-4 satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via a redundant/secure Inter Control Center Communication Protocol (ICCP) that all RC's, BA's TOP's use to exchange the required data.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

In regard to R19, this requirement is only administrative in nature as an entity must demonstrate that is has the ability exchange data with all entities that it provides and receives information from to perform its monitoring and assessments, to include operational planning before it can be certified to perform the TOP function. In addition, TOP entities are on a 3-year audit cycle and in which the entity's data exchange capabilities with other entities are reviewed. In regard to R22, this requirement is only administrative in nature as an entity must demonstrate that is has the ability exchange data with all entities that it provides and receives information from to perform its monitoring and assessments before it can be certified to perform the BA function. In addition, BA entities are on a 3-year audit cycle in which the entity's data exchange capabilities with other entities are reviewed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
NPCC supports the SDTs position. However, we would consider supporting a position in which these Requirements would be recommended to the phase two analysis, and that they should be incorporated into the entity certification process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	

Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Having data exchange capabilities does not add a reliability benefit. Something must be done with the data in order to impact reliability. The authority to request and do something with the data is adequately covered in TOP-003-3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains	

Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

21. ***The SDT is proposing to retire VAR-001-5, Requirement R2. Do you agree with the SDT's proposal to retire Requirement R2 of VAR-001-5? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation*.**

Summary Response:

The SDT determined Requirement R2 should be retired for the following reasons:

VAR-001-5, Requirement R2 states "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load"

VAR-001-5 R2 contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately. The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the Operational Planning Assessment as described and required in TOP-002-4 and the criteria described in TOP-001-4, R10 the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Using Real-time monitoring and making real-time decisions on voltage is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

Specifically,

1. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement 1 of this standard requires the TOP to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). Requirement 2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

   An Operating Plan is defined by NERC as *"A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."*

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition. One such tool are reactive resources. The TOP MUST have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate number is determined through analysis.

2. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement 13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes and Requirement 14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

   This is a requirement that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of the TOP exists here as it did under TOP-002-4. The TOP MUST have an adequate number of reactive resources to mitigate SOL exceedances. The adequate number is determined through analysis.

The second sentence of VAR-001-5 R2 states "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the Enhanced Periodic Review group during its September 2016 meeting and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then that perhaps this language be moved to a guidance section or document.

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No

Document Name	
Comment	

Duke Energy disagrees with the drafting team's proposal to retire VAR-001-5 R2. This requirement ensures that Operators have the necessary reactive resources they need to provide voltage control. Eliminating this requirement would take away an Operators ability to justify keeping a reactive resource in service and potentially negatively impact the reliability of the grid.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT determined Requirement R2 should be retired for the following reasons:

VAR-001-5, Requirement R2 states "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load"

VAR-001-5 R2 contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately. The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the Operational Planning Assessment as described and required in TOP-002-4 and the criteria described in TOP-001-4, R10 the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Using Real-time monitoring and making real-time decisions on voltage is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

Specifically,

3. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement 1 of this standard requires the TOP to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). Requirement 2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition. One such tool are reactive resources. The TOP MUST have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate number is determined through analysis.

4. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement 13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes and Requirement 14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

   This is a requirement that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of the TOP exists here as it did under TOP-002-4. The TOP MUST have an adequate number of reactive resources to mitigate SOL exceedances. The adequate number is determined through analysis.

The second sentence of VAR-001-5 R2 states "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the Enhanced Periodic Review group during its September 2016 meeting and agreed to herein, this language is

guidance or a measure and is unnecessary in the requirement. It was suggested then that perhaps this language be moved to a guidance section or document.

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power disagrees with the proposed retirement for VAR-001-5 R5 because, while it is difficult to provide evidence for, the requirement for scheduling sufficient reactive resources is important.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined Requirement R2 should be retired for the following reasons: VAR-001-5, Requirement R2 states “Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load” VAR-001-5 R2 contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately. The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the Operational Planning Assessment as described and required in TOP-002-4 and the criteria described in TOP-001-4, R10 the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Using Real-time monitoring and making real-time decisions on voltage is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall	

use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

Specifically,

5. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement 1 of this standard requires the TOP to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). Requirement 2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition. One such tool are reactive resources. The TOP MUST have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate number is determined through analysis.

6. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement 13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes and Requirement 14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

   This is a requirement that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of the TOP exists here as it did under TOP-002-4. The TOP MUST have an adequate number of reactive resources to mitigate SOL exceedances. The adequate number is determined through analysis.

The second sentence of VAR-001-5 R2 states "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the Enhanced Periodic Review group during its September 2016 meeting and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then that perhaps this language be moved to a guidance section or document.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to comments submitted by Edison Electric Institute.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Ensuring that an entity has sufficient reactive resources to regulate voltage levels under both normal and contingency conditions is an inherent function of the TOP, and although having a standard requirement may add some reinforcement, it does not necessarily add to reliability. If the TOP fails to provide adequate reactive resources to regulate voltage, it could lead to voltage collapse, damage to equipment, system overloads and blackouts. (All of which are covered in other NERC Reliability Standards). Having this standard requirement in place places an administrative burden on the TOP and takes their time away from operating the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT is not opposed to the retirement of this requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chris Wagner - Santee Cooper - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 1, 5, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
This was not reviewed.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is concerned that without VAR-001-5 Requirement R2, Transmission Operators may not put emphasis on scheduling sufficient reactive resources to regulate voltage levels. This could lead to voltage collapse. Additionally, the SDT is relying on the fact that voltage limit is a form of an SOL. Since there is no definition of SOL exceedance, entities may not adequately address voltage issues within the OPA, whereas this requirement emphasizes regulating voltage levels. Texas RE recommends removing the reference to "Compliance Monitor" in C1.2 Data Retention. Compliance Monitor is an outdated term and there is no definition for it.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined Requirement R2 should be retired for the following reasons: VAR-001-5, Requirement R2 states "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load" VAR-001-5 R2 contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately. The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the Operational Planning Assessment as described and required in TOP-002-4 and the	

criteria described in TOP-001-4, R10 the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Using Real-time monitoring and making real-time decisions on voltage is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

Specifically,

7. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement 1 of this standard requires the TOP to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). Requirement 2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition. One such tool are reactive resources. The TOP MUST have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate number is determined through analysis.

8. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

Requirement 13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes and Requirement 14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

This is a requirement that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of the TOP exists here as it did under TOP-002-4. The TOP MUST have an adequate number of reactive resources to mitigate SOL exceedances. The adequate number is determined through analysis.

The second sentence of VAR-001-5 R2 states "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the Enhanced Periodic Review group during its September 2016 meeting and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then that perhaps this language be moved to a guidance section or document.

22. *Please provide any additional comments for the SDT to consider that have not already been provided in the questions above*.

Summary Response:

MOD: Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

SER Phase II: The SER Phase II effort can also be followed on the Standards Efficiency Review Project Page.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	

Although ACES agrees with the retirement Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-030-3 and MOD-001-2, ACES cautions the unique position of some of its members requiring them to obtain transmission service across multiple BAAs and participate in transactions between ISO/RTO and non-ISO/RTO entities. This has allowed those entities to witness first-hand the mismatched ATC values across the seams shared by adjacent Transmission Providers. For that reason, we advocated for this at that time and still hold the position that the retirement of these standards should be contingent upon analysis of their retirement impact on entities with such unique situations, like North Carolina Electric Membership Corporation (NCEMC) that depends on the transmission services to meet its load obligation, reliably and economically, within each of their BAAs.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-001-2:

Requirement R1: TOPs are not required to determine TFC or TTC; therefore, this is a conditional obligation - and there is no requirement that TOPs coordinate their methodologies. The definition of AFC explicitly includes the term "…further commercial activity…" which is explicit that this relates to commercial activity, not reliability-related activity. This requirement also has no performance elements, so there is nothing to measure against.

Requirement R1, Requirement Parts 1.1.1 thru 1.1.4 are expressly the definition of SOLs and are duplicative of the definition. Requirement Part 1.1.5 therefore adds nothing, as there is no provision for "Other SOLs."

Requirement R1, Requirement Part 1.2.2 are Additions and retirements are Long-term planning related and would be reflected in operational models. Planned outages for the operating time horizon is expressly addressed in TOP-001-4 R9.

Requirement R1, Part 1.3: any reliability-related constraints are already expressed in OPAs and the requirements to operate within SOLs.

Requirement R1, Requirement Part 1.3.1: generation to load transfers does not, in most cases, reflect any physical arrangement. Such transfers assume a system between the two that can handle the transfer; and this system must be operated to respect SOLs.

The SDT determined that Requirement R1, Requirement Part 1.3.2 is ambiguous. There are several distribution factors; one related to outages, one related to transfers, and one related to a composite between the two. It is ambiguous to which of these distribution factors is being addressed.

Requirement R2: applies to TSP and Available Flowgate Capacity or Available Transfer Capability. Requirement R1 applies to TOP and Total Flowgate Capacity or Total Transfer Capacity. Otherwise, Requirement R2 is very similar to Requirement R1, and the rationale to retire Requirement R1 also applies to Requirement R2.

Requirement R3: CBM is defined as "The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs) whose loads are located on that Transmission Service Provider's system to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

There is no obligation for a TSP to determine CBM; this requirement just applies to TSPs that elect to determine CBM. The requirement contains no criteria regarding what the CBMID must include, rather that generally describing the method.

Further, this requirement has no performance obligation, but to just to have a document; therefore, is administrative.

Requirement R4: The SDT vetted Requirement R4 and determined that Requirement R4 does not require TOPs to determine TRM and establish measurable criteria for what the TRMID must include. Further, R4 does not establish any criteria for the TRMID, just that the

TOP that has TRM must have a document describing its methodology. Therefore, this requirement is simply administrative on an open-ended conditional duty. **Requirement R5** and its Requirement Parts: Requirement Part 5.1: as the TOP or TSP is not required to have a TFC or TTC methodology, or an ATCID, CBMID, or TRMID, other entities that may have a reliability-related need for these, that information is routinely pursuant to the data specifications of the RC (in INT-010-2.1) and the TOP (in TOP-003-3). In Real-time operation of the BES, the limitations related to similar issues is fully addressed by the obligations of TOP-001-4; specifically as related to operating within SOLs and IROLs and issuing and responding to Operating Instructions. Requirement Part 5.2 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. Requirement Part 5.3 and subparts: OASIS is a mechanism to assure that all market participants have simultaneous access to all market-data, such that no participant has an advantage. To provide this information to any participant via any mechanism rather that OASIS or a publicly-accessible company website becomes a FERC SOC violation. **Requirement R6:** If this data had a reliability-related need, it would be addressed via the data specifications in INT-010-2.1 (for RC) and TOP-003-3 (for TOP). However, AFC, ATC, TFC, and TTC are not mandatory to establish; thus the party requested for this data may very well not have the data to provide. Further, various TOPs or TSPs that would have these elements are not required to coordinate them, which could easily lead to widely disparate methodologies. Finally, as market-related data, this data would likely be subject to FERC Standards of Conduct, which would require that the data be publicly posted for all other market participants to access.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
None.	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE does not have additional comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI member companies would like to note our appreciation to NERC for the opportunity afforded to the Industry to provide input into the planned SER Phase I Retirements (Project 2018-03). We are very supportive of those efforts as well as the deferments of some requirements to the SER Phase 2 Project. While we understand that the CIP Standards will also be addressed in the SER Phase 2 Project, we ask that NERC provide additional clarity to the Industry as to how and when these Phase 2 efforts will all tie together. Such an effort would be appreciated by the Industry and would resolve any concerns companies may have related to the Phase 2 effort.

Additionally, EEI Members have noted that when NERC originally queried the Industry for recommendations for possible Reliability Standard Requirements that merit consideration for the Phase 1 effort, the Industry was also told that the CIP Standards would not be considered until the Phase 2 effort. Now that Phase 2 is beginning, EEI looks forward to NERC "consult[ing] with the SER Advisory Group and stakeholders, on a plan to address the CIP Standards in the SER." (see NERC Standards Efficiency Review Project Update | August 3, 2018) We additionally ask NERC to provide greater clarity and detail as to when stakeholder outreach, similar to the Phase 1 Industry solicitation, will be initiated for CIP Reliability Standards? While NERC did receive a small number of CIP related suggestions within the Phase 1 solicitation, the focus was on the O&P Standards. EEI member companies believe additional solicitation focused on CIP is necessary for effectively addressing CIP Standards in Phase 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support of the SER Phase I effort. Your comments regarding SER Phase II effort and CIP standards will be forwarded to the appropriate NERC staff leading that effort. The SER Phase II effort can also be followed on the Standards Efficiency Review Project Page.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	
LaTroy Brumfield - American Transmission Company, LLC - 1	

Answer	
Document Name	
Comment	
At the onset of the Standards Efficiency Review Project NERC stated that there would be an effort to review/revise the CIP standards during phase 2 of the project. The perception by industry was that the CIP standards would go through an iteration of review/revision like the process used by NERC for the O&P standards during phase 1. Can NERC please clarify whether the CIP standards will be more closely reviewed/revised and vetted by industry in subsequent phase of this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. NERC recently developed concepts for the SER Phase II effort that include a CIP Standards Efficiency Review, and solicited industry comments through March 22, 2019. Your comments regarding the SER Phase II effort and CIP standards will be forwarded to the appropriate NERC staff leading that effort. The SER Phase II effort can also be followed on the Standards Efficiency Review Project Page.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	
Document Name	
Comment	
Westar and Kansas City Power & Light Co. support Edison Electric Institute's comments to Question 22.	
Likes 0	

Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute in Question 22.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Please see responses to comments from Edison Electric Institute in Question 22.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Idaho Power has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from Edison Electric Institute.	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy is appreciative of the efforts taken by NERC and SDT to review the reliability standards and identify these requirements and standards for retirement. As the efforts with Phase I were dedicated to the O&P Standards, NV Energy is anticipating that in Phase II that this same in-depth review will be conducted for the CIP Standards and Requirements. NV Energy is also looking forward to the inventory of requirements that will be identified with the application of the concepts for the Phase II review.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support of the SER Phase I effort. Your comments regarding SER Phase II effort and CIP standards will be forwarded to the appropriate NERC staff leading that effort. The SER Phase II effort can also be followed on the Standards Efficiency Review Project Page	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Please see response to the comments from the ISO/RTO Council Standards Review Committee.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	

None.	
Likes 0	
Dislikes 0	
Response	

Additional comments submitted by Duke Energy

Duke Energy Comment Response to Question 11: for 2018-03 Standards Efficiency Review Retirements comment period ending on: 4/12/2019 8:00 PM

Question:

11. The SDT is proposing to retire MOD-004-1, Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, and R12 (all). Do you agree with the SDT's proposal to retire MOD-004-1? If you do not agree, please provide comments. Or, if you agree but have comments or suggestions on the SDT's proposal, please provide your explanation.

☐ Yes

☒ No

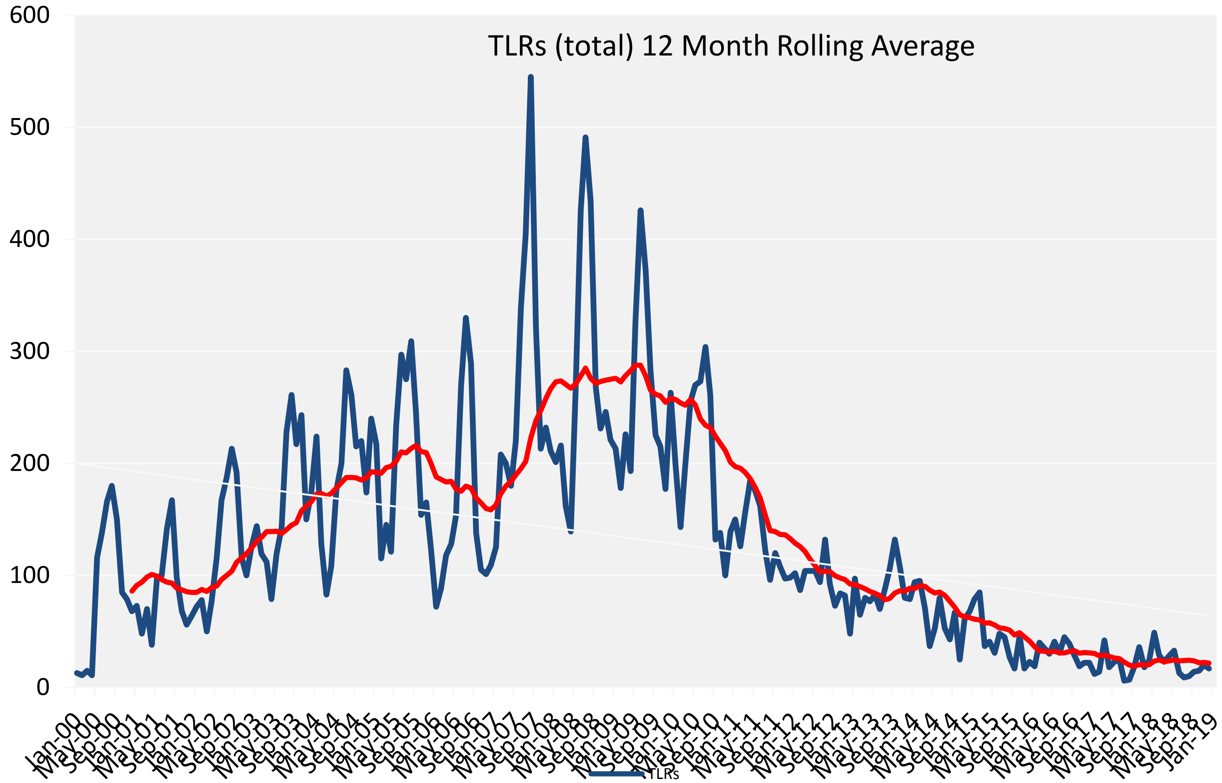
Comments:

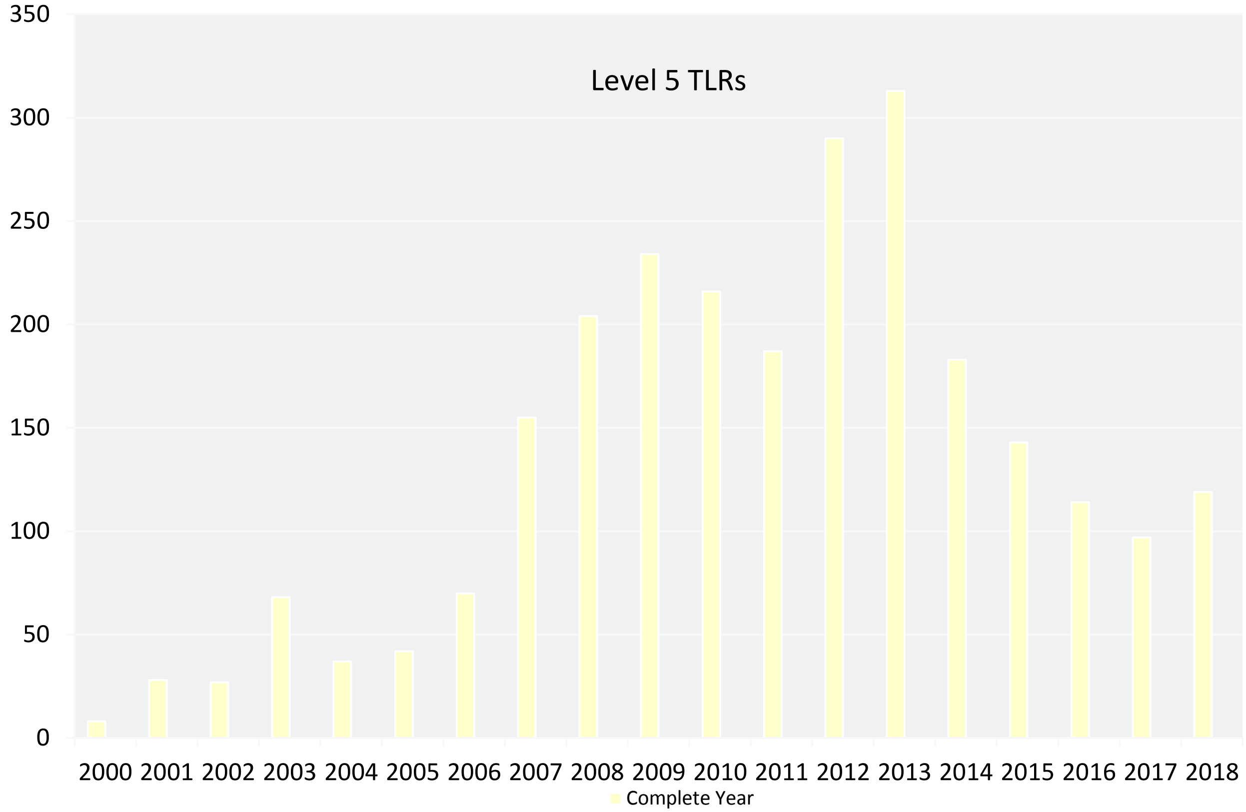
While Duke Energy would support the retirement of these MOD standards, we cannot do so if MOD-001-2 is withdrawn. The MOD standards promote reliability of the grid by putting in place common boundaries and provisions that are necessary for various calculations that need to be performed. These calculations are important to reliability by providing the baseline for understanding the operational need. By retiring the MOD standards, and not having MOD-001-2 in place, there will not be provisions in place to aid an entity in calculating transfer capability. There will not be any boundaries in place for the curtailment of service. We disagree with the commercial based focus that the drafting team took in the technical rationale document. While these MOD standards (and ATC calculation) may have some commercial based elements to them, they also put in place valuable boundaries that help promote consistency in how the industry calculates these values. Removing these boundaries does not promote reliability for the Bulk Electric System and introduces additional burden to the real-time System Operator.

The expectation of the System Operators to ensure the reliability of the BES in the real-time when there have been no requirements to ensure how ATC is calculated or coordinated beyond what is required by NAESB is unrealistic. Some of the most glaring issues with relying solely upon NAESB to regulate the calculation of ATC are: FERC does not have oversight for non-jurisdictional TSPs and therefore cannot require them to incorporate NAESB standards. Also, while NAESB has acted on the recommendations of the MOD-A project to incorporate any of the gaps created by the retirement of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3 and adoption of MOD-001-2, FERC has not acted on either the NERC or NAESB filings. Further, NAESB has not been requested to modify proposed standards to incorporate any of the gaps created by the retirement of the proposed MOD-001-2.

Additionally, the lack of any NERC regulation for consistent ATC methodologies and requirements for sharing of data and could potentially lead to an increase of TLRs being called as this would be the only tool System Operators could utilize to combat rampant loop flow impacts on the BES. This could very well lead to capacity concerns and load shedding as the increase in TLRs could include firm curtailments causing capacity shortages. Without mandatory ATC standards, a TSP would be able to sell as much service as possible. The overselling of service and the overscheduling of ATC Paths will lead to an increase of FIRM TLR, potentially forcing Transmission Operators and Load Serving Entities to shed FIRM load to comply with the TLR. Over the past eight years the MOD-001, 28,29, & 30 standards have been effective the industry has seen a dramatic reduction in FIRM TLRs.

Included in the Attachment with Duke Energy's response to this question is the rolling 12-month average of TLRs from the NERC website. Notice the reduction in TLRs from 2008-2011 when the MOD standards were first published (in 2008 when TSP started to incorporate the MOD standards into their ATC methodologies) and 2011 (when the MOD standards were mandatory and enforceable).


TLRs (total) 12 Month Rolling Average
600
500
400
300
200
100
0
TLRs



Additional comments submitted by ReliabilityFirst

ReliabilityFirst does not agree with the removal of PRC-004-6 Requirement R4 for the following reason:

1. The concept of a declaration for no identifiable cause is currently introduced in R4 and in the Application Guidelines (now called Supplemental Material) for R4. The one statement from the Application Guidelines for R4 in version 5(i) states,

a. 'The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.'

This statement needs to be retained somewhere as an explanation for this use of the declaration. The declaration is also referenced in R5, but for a different reason (problem found but CAP won't improve reliability of BES). The declaration associated with R4 would be a cause that is 'unknown/unexplainable' and all testing and analysis comes up empty. There wouldn't be a CAP, since nothing was found broken, and the declaration is used to close the investigation. In MIDAS, the CAP Completion Status would be 'declaration' rather than improperly coding as 'CAP – Complete', since no CAP was developed.

As far as the administrative requirement of 'corrective action at least once every two calendar quarters', ReliabilityFirst recommends the following for consideration:

R4:
Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation ~~at least once every two full calendar quarters after the Misoperation was first identified~~, maintaining documentation in sufficient detail to provide clear delineation of the stage and findings of the investigation until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*

☐The identification of the cause(s) of the Misoperation; or
☐A declaration that no cause was identified.

End of Report

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-4
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning]*

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

R7. Reserved.

M7. Reserved.

---

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R8. Reserved.

M8. Reserved.

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. Compliance Monitoring and Enforcement Processes:

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.3. 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 Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.

- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- If a Generator Owner or Transmission Owner 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 and all subsequent compliance records.

1.4. 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	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
R4. Reserved.				
R5. Reserved.				

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R6.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7. Reserved.				
R8. Reserved.				

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	TBD	Adopted by NERC Board of Trustees	R7 and R8 and associated elements approved by NERC Board of Trustees for retirement as part of Project 2018-03 Standard Efficiency Review Retirements

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-~~3~~4
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** ~~The first day of the first calendar quarter that is twelve months beyond the date approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter twelve months following BOT adoption~~See Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**1.1.**~~ The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.

- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

~~**1.2.**~~ The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~**2.1.**~~ The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.

- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).

- A practice that has been verified by testing, performance history or engineering analysis.

~~2.2.~~ The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

~~2.2.1.~~ Equipment Rating standard(s) used in development of this methodology.

~~2.2.2.~~ Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

~~2.2.3.~~ Ambient conditions (for particular or average conditions or as they vary in real-time).

~~2.2.4.~~ Operating limitations.[1]

~~2.3.~~ A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

~~2.4.~~ The process by which the Rating of equipment that comprises a Facility is determined.

~~2.4.1.~~ The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

~~2.4.2.~~ The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~3.1.~~ The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

~~3.2.~~ The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

~~3.2.1.~~ Equipment Rating standard(s) used in development of this methodology.

~~3.2.2.~~ Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

~~3.2.3.~~ Ambient conditions (for particular or average conditions or as they vary in real-time).

~~3.2.4.~~ Operating limitations.[2]

~~3.3.~~ A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

~~3.4.~~ The process by which the Rating of equipment that comprises a Facility is determined.

~~3.4.1.~~ The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

~~3.4.2.~~ The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.~~Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)~~

M4. Reserved. ~~Each Transmission Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement 4. The Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its documentation for determining its Facility Ratings or its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement R4. (Retirement approved by NERC BOT pending applicable regulatory approval.).~~

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R5. Reserved. ~~If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)~~

M5. Reserved.~~If the Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology or a Generator Owner's documentation for determining its Facility Ratings, the Transmission Owner or Generator Owner shall have evidence, (such as a copy of a dated electronic or hard copy note, or other comparable evidence from the Transmission Owner or Generator Owner addressed to the commenter that includes the response to the comment,) that it provided a response to that commenting entity in accordance with Requirement R5. (Retirement approved by NERC BOT pending applicable regulatory approval.)~~

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

R7. Reserved.~~Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

M7. Reserved.~~Each Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R7.~~

R8. Reserved.~~Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely~~

~~and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~As scheduled by the requesting entities:~~

~~**8.1.1.** Facility Ratings~~

~~**8.1.2.** Identity of the most limiting equipment of the Facilities~~

~~**8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:~~

~~**8.2.1.** Identity of the existing next most limiting equipment of the Facility~~

~~**8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.~~

M8. Reserved.~~Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.~~

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. Compliance Monitoring and Enforcement Processes:

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations

- Complaints

1.3. 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 Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.
- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- ~~The Generator Owner and Transmission Owner shall each keep evidence for Measure M4, and Measure M5, for three calendar years. (Retirement approved by FERC effective January 21, 2014.)~~
- ~~The Generator Owner shall keep evidence for Measure M7 for three calendar years.~~
- ~~The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.~~
- If a Generator Owner or Transmission Owner 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 and all subsequent compliance records.

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	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• 2.2.4
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved. ~~(Retirement approved by FERC effective January 21, 2014.)~~	~~The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.~~	~~The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.~~	~~The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.~~	~~The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)~~
R5. Reserved. ~~(Retirement approved by FERC effective January 21, 2014.)~~	~~The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)~~	~~The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request.~~ ~~OR~~ ~~The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings methodology or Facility~~	~~The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request.~~ ~~OR~~ ~~The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility~~	~~The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		~~Ratings documentation but did not indicate why no change will be made. (R5)~~	~~Ratings documentation. (R5)~~	
R6.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7. Reserved.	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.~~	~~The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days.~~ ~~OR~~ ~~The Generator Owner failed to provide its Facility~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Ratings to the requesting entities.~~
R8. Reserved.	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal~~	~~The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)~~ ~~OR~~ ~~The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2)~~ ~~OR~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~to 35 calendar days late. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)~~	~~The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2)~~ ~~OR~~ ~~The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)~~

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from "Lower" to "Medium"	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	TBD	Adopted by NERC Board of Trustees	Requirements R7 and R8 and associated elements approved by NERC Board of Trustees for retirement as part

			of Project 2018-03 Standard Efficiency Review Retirements

A. Introduction

1. **Title:** Evaluation of Interchange Transactions
2. **Number:** INT-006-5
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
    - **4.1.** Balancing Authority
    - **4.2.** Transmission Service Provider
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

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 Balancing Authority shall maintain evidence to show compliance with R1 and R3 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider 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.

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4. Reserved.						
R5. Reserved.						

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	
5	TBD	Adopted by the NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange[2]	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status[2]	BA Prepares Confirmed Interchange for Implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classificatio n**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - All reliability entities involved in the Arranged Interchange are valid.
  - Generation source and Load sink are defined.
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
  - Distribute notification as each entity approves or denies an Arranged Interchange.
  - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
  - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

  - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange
- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

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 R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny

for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:
TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

A. Introduction

1. **Title:** Evaluation of Interchange Transactions
2. **Number:** INT-006-~~4~~5
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Service Provider
5. **Effective Date:** ~~First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~See Implementation Plan.

~~6. **Background:** This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.~~

~~The content of INT-006-4 has been revised and expanded in the following manner:~~

- ~~R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.~~
- ~~R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.~~
- ~~R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.~~
- ~~R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.~~

- ~~R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.~~
- ~~Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.~~

B. Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**3.1.** If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.~~

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request. ~~and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)~~

R4. Reserved.~~Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

- ~~It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.~~
- ~~It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.~~
- ~~It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.~~

M4. Reserved. ~~Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)~~

R5. Reserved.~~For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

~~**5.1.** The Source Balancing Authority,~~

~~**5.2.** Each Intermediate Balancing Authority,~~

~~**5.3.** Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,~~

~~**5.4.** Each Transmission Service Provider included in the Arranged Interchange, and~~

~~**5.5.** Each Purchasing Selling Entity included in the Arranged Interchange.~~

M5. Reserved.~~Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)~~

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 Balancing Authority shall maintain evidence to show compliance with R1~~,~~ and R3~~, R4, and R5~~ for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider 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.

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3.	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.~~, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.~~	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved.	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.~~
R5. Reserved.	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.~~	~~The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.~~ ~~OR~~ ~~The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.~~

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	
5	TBD	Adopted by the NERC Board of Trustees	Requirements R3.1, R4, and R5 retired under Project 2018-03 Standard Efficiency Review Retirements.

Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange[4]	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status[4]	BA Prepares Confirmed Interchange for Implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.
[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - All reliability entities involved in the Arranged Interchange are valid.
  - Generation source and Load sink are defined.
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
  - Distribute notification as each entity approves or denies an Arranged Interchange.
  - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
  - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

  - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange
- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

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 R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny

for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:
TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

A. Introduction

1. **Title:** Implementation of Interchange
2. **Number:** INT-009-3
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**
   4.1. Balancing Authority
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

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 Balancing Authority shall maintain evidence to show compliance with R1 and R3 for the most recent 3 months plus the current month.

   If a Balancing Authority 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.

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange not yet captured in the Composite Confirmed Interchange.
R2. Reserved.						
R3.	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	
3	TBD	Adopted by NERC Board of Trustees	Requirement R2 retired under Project 2018-03 Standard Efficiency Review Retirements.

A. Introduction

1. **Title:** Implementation of Interchange
2. **Number:** INT-009-3
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**
   4.1. Balancing Authority
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~per INT-010-2~~ not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~as directed per INT-010-2~~ not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

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 Balancing Authority shall maintain evidence to show compliance with R1 and R3 for the most recent 3 months plus the current month.

   If a Balancing Authority 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.

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~per INT-010-2~~ not yet captured in the Composite Confirmed Interchange.
R2. Reserved.						
R3.	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	
3	TBD	Adopted by NERC Board of Trustees	Requirement~~s~~ R2 ~~3.1, R4, and R5~~ retired under Project 2018-03 Standard Efficiency Review Retirements.

A. Introduction

1. **Title:** Implementation of Interchange

2. **Number:** INT-009-~~2.1~~3

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

4. **Applicability:**

   4.1. Balancing Authority

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

~~6. **Background:** This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.~~

~~The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.~~

~~The content of INT-009-2 has been revised and expanded in the following manner:~~

- ~~R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.~~
- ~~R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.~~
- ~~R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.~~

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~per INT-010-2~~ not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~as directed per INT-010-2~~ not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. Reserved.~~The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]~~

M2. Reserved.~~The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)~~

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

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 Balancing Authority shall maintain evidence to show compliance with R1~~, R2~~ and R3 for the most recent 3 months plus the current month.

    If a Balancing Authority 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.

    - Compliance Audit
    - Self-Certification
    - Spot Checking
    - Compliance Investigation
    - Self-Reporting
    - Complaint

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange ~~per INT-010-2~~ not yet captured in the Composite Confirmed Interchange.
R2. Reserved.	~~Real-time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	
3	TBD	Adopted by NERC Board of Trustees	Requirement R2 retired under Project 2018-03 Standard Efficiency Review Retirements.

~~Guidelines and Technical Basis~~

~~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 R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.~~

A. Introduction

1. **Title:** Reliability Coordination – Monitoring and Analysis
2. **Number:** IRO-002-7
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. Reserved.

M1. Reserved.

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 R2 and R4 and Measures 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. Reserved.				
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 capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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

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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

6	TBD	Adopted by the NERC Board of Trustees	Requirement R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of IRO-002-4 in Project 2014-03 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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: (*note*: R1 proposed for retirement in IRO-002-7 as part of Project 2018-03 Standard Efficiency Review Retirements)
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 and IRO-002-7):
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-~~6~~7
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. Reserved.

M1. Reserved.

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 R2 and R4 and Measures 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. Reserved.				
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 capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	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.	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.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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

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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

Version	Date	Action	Change Tracking
6	TBD	Adopted by the NERC Board of Trustees	Requirement R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of IRO-002-4 in Project 2014-03 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.

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: (*note*: R1 proposed for retirement in IRO-002-~~6~~ 7 as part of Project 2018-03 Standard Efficiency Review Retirements)

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 and IRO-002-~~6~~7):
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-~~5~~7
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. Reserved.~~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. Reserved. ~~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. Reserved.	~~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	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
			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 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	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 unsuccessful test, initiated action to restore the redundant functionality in more than 4	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 functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6	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; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	hours and less than or equal to 4 hours.	hours and less than or equal to 6 hours.	hours and less than or equal to 8 hours.	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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~~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	February 9, 2017	Adopted by Board of Trustees	Revised
5	April 17, 2017	FERC letter Order approved IRO-002-5. Docket No. RD17-4-000	

6	TBD	Adopted by the NERC Board of Trustees	Requirement R1 retired as part of Project 2018-03 Standards Efficiency Review Retirements.

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 and IRO-002-5 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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: (*note*: R1 proposed for retirement in IRO-002-7~~6~~ as part of Project 2018-03 Standard Efficiency Review Retirements)
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 and IRO-002-7~~6~~):
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:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-6
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

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

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Reserved.

M4. Reserved.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall

implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, and R3, Measures M1, M2, and M3 for a minimum of 12 calendar months following the completion of each Requirement.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, and R3, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
R4. Reserved.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6.	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)
6	TBD	Adopted by the NERC Board of Trustees	R4 retired under Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

---

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing

devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

  Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

  1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
  2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
  3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
  4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
  5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
  6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Composite Protection System*

operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the

Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

Example 5: An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

Example 5c: If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

Example 6a: An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

Example 6b: Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

Example 6c: An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Example 6d: Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example 6e: A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations. In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static

voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was

caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation . If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional

---

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner’s notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1 or R3, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity’s control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity’s control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity’s other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection

Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

Example R5a: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5b: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance

relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

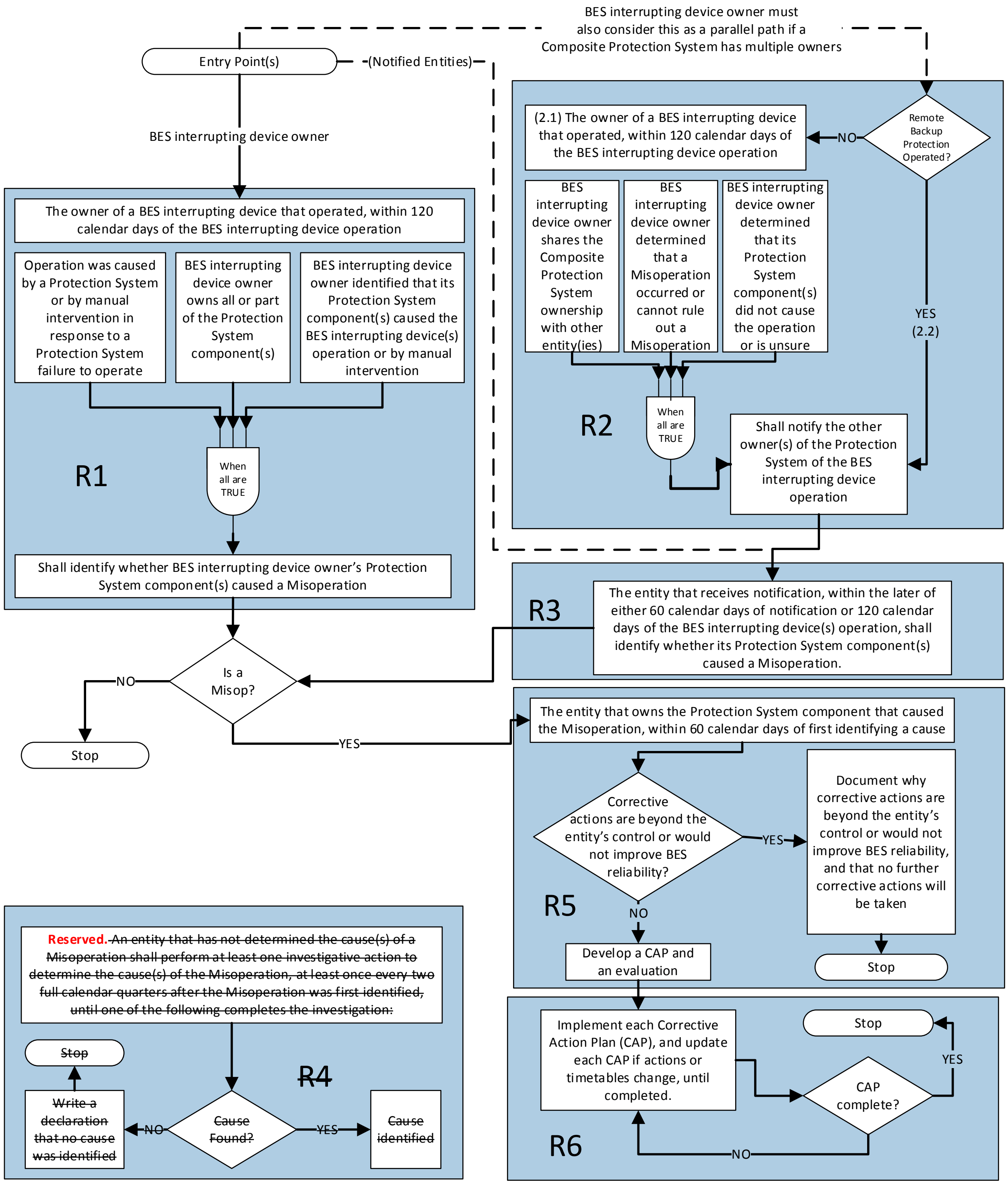
Example R6d: Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-6
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems for BES Elements, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

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

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Reserved.

M4. Reserved.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall

implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, and R3, Measures M1, M2, and M3 for a minimum of 12 calendar months following the completion of each Requirement.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, and R3, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
R4. Reserved.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6.	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)
6	TBD	Adopted by the NERC Board of Trustees	R4 retired under Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

---

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example
The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example
The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example
The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing

devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Composite Protection System*

operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault
The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault
An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the

Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

Example 5: An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.

Example 5c: If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

Example 6a: An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

Example 6b: Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

Example 6c: An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Example 6d: Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example 6e: A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.
In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static

voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was

caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation ~~under Requirement R4~~. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1 or R3, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

Example R5a: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5b: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

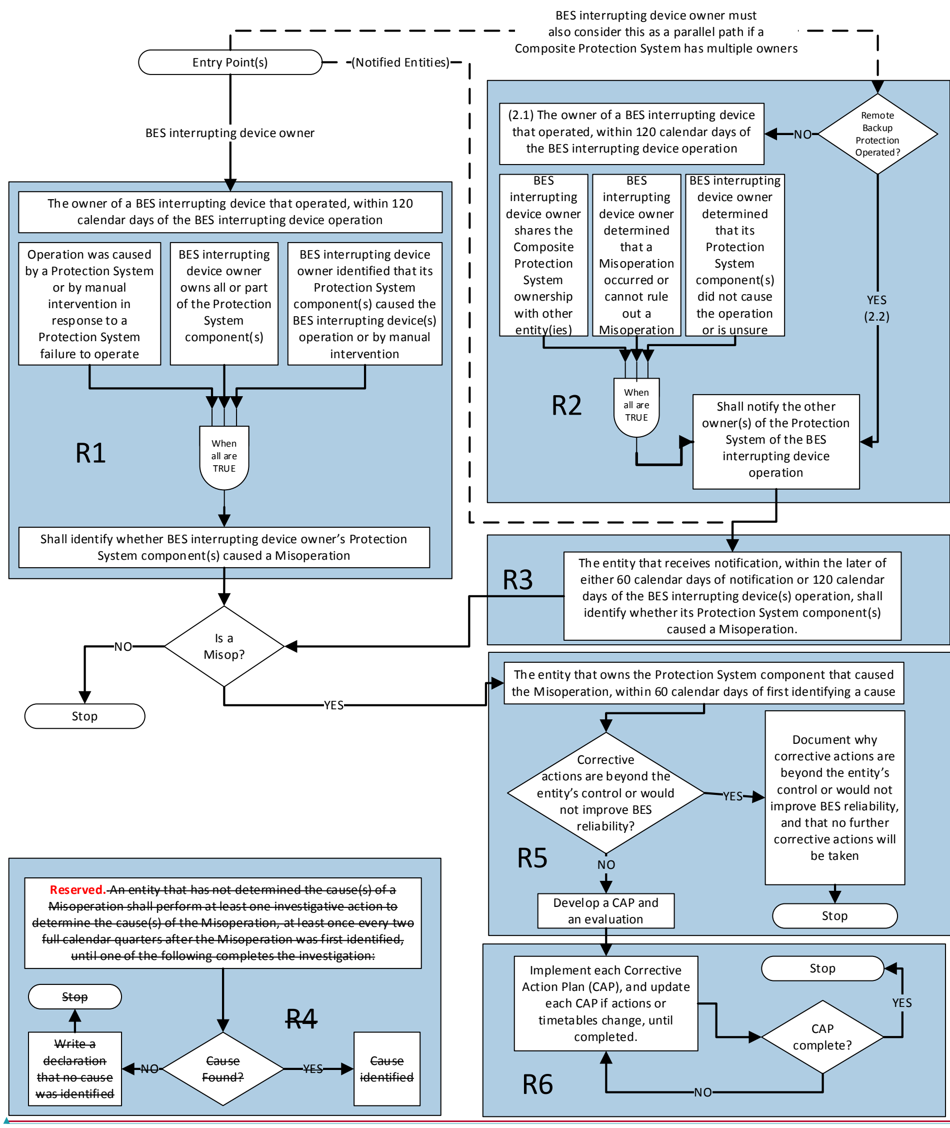
Example R6d: Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

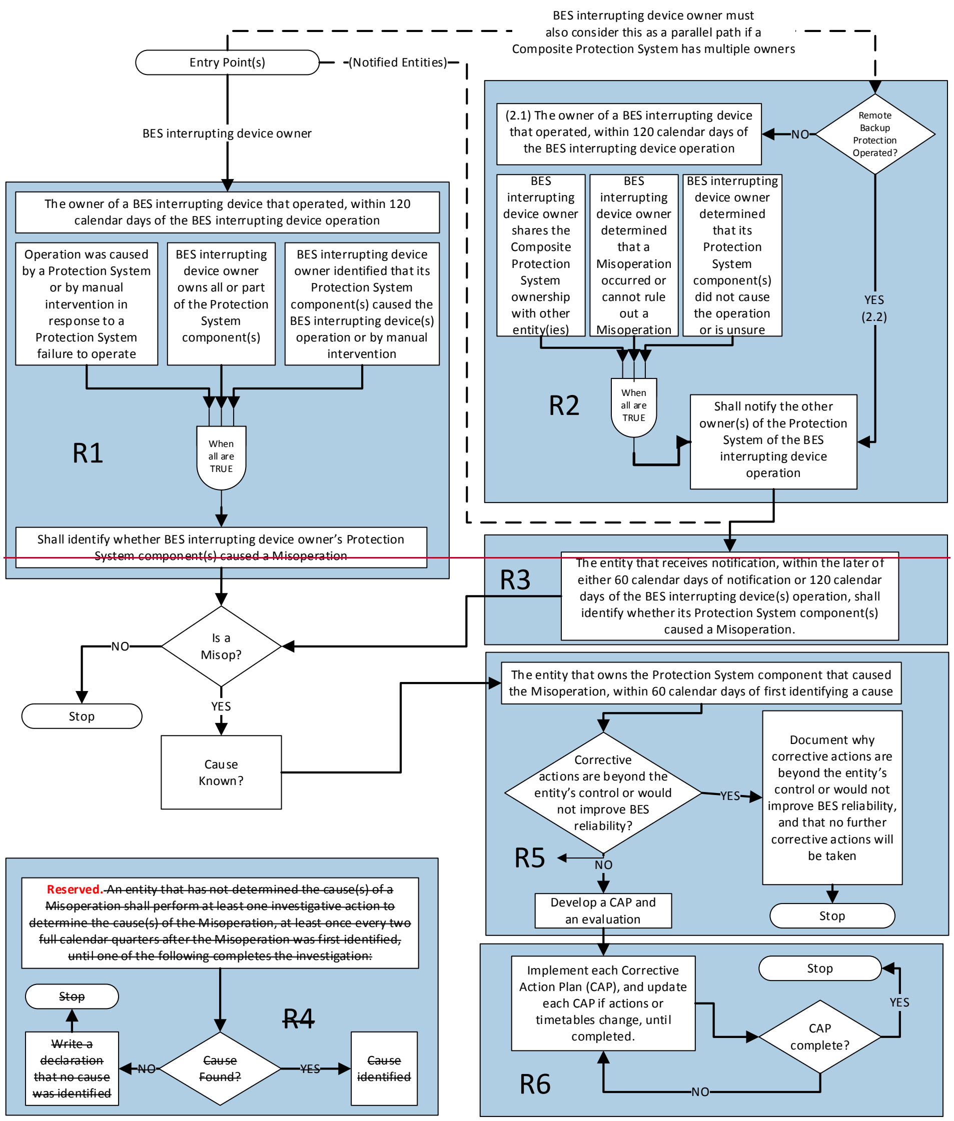
CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Field Code Changed



BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
R1
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
When all are TRUE
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
R2
Remote Backup Protection Operated?
NO
YES (2.2)
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
When all are TRUE
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
Is a Misop?
NO
Stop
YES
Cause Known?
R5
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
Stop
NO
Develop a CAP and an evaluation
~~R4~~
Reserved. ~~An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action to determine the cause(s) of the Misoperation, at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:~~
~~Stop~~
~~Write a declaration that no cause was identified~~
~~NO~~
~~Cause Found?~~
~~YES~~
~~Cause identified~~
R6
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
CAP complete?
YES
Stop
NO

A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-~~5(i)~~6
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See ~~Project 2008-02.2~~ Implementation Plan.

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*~~

- ~~The identification of the cause(s) of the Misoperation; or~~
- ~~A declaration that no cause was identified.~~

M4. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.~~

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, and R3~~, and R4~~, Measures M1, M2, and M3~~, and M4~~ for a minimum of 12 calendar months following the completion of each Requirement.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, and R3~~, and R4~~, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

D. ~~Table of Compliance Elements~~Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4. Reserved.	~~Operations Assessment, Operations Planning~~	~~High~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.~~	~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late.~~ ~~OR~~ ~~The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.~~

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR ~~(See next page)~~

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R5~~	~~(Continued)~~		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6.	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC’s Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)
6	TBD	Adopted by the NERC Board of Trustees	Requirement R4 retired under Project 2018-03 Standards Efficiency Review Retirements.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

---

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. ~~Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary.~~ Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. ~~The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.~~

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation~~ under Requirement R4~~. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R1b: A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Example R2b: A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Example R2c: Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement~~ ~~R1 and continue its investigation for a cause of the Misoperation~~ under Requirement R4~~. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

~~Requirement R4~~

~~The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.~~

~~A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.~~

~~The following is an example of investigative actions taken to determine the cause of an identified Misoperation:~~

> ~~**Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.~~

~~Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize~~

~~that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.~~

~~The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.~~[8]

~~Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.~~

~~The following are examples of a declaration where no cause was determined:~~

> ~~**Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.~~
>
> ~~**Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.~~

[8] ~~NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.~~

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1 or~~,~~ R3~~ or R4~~, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

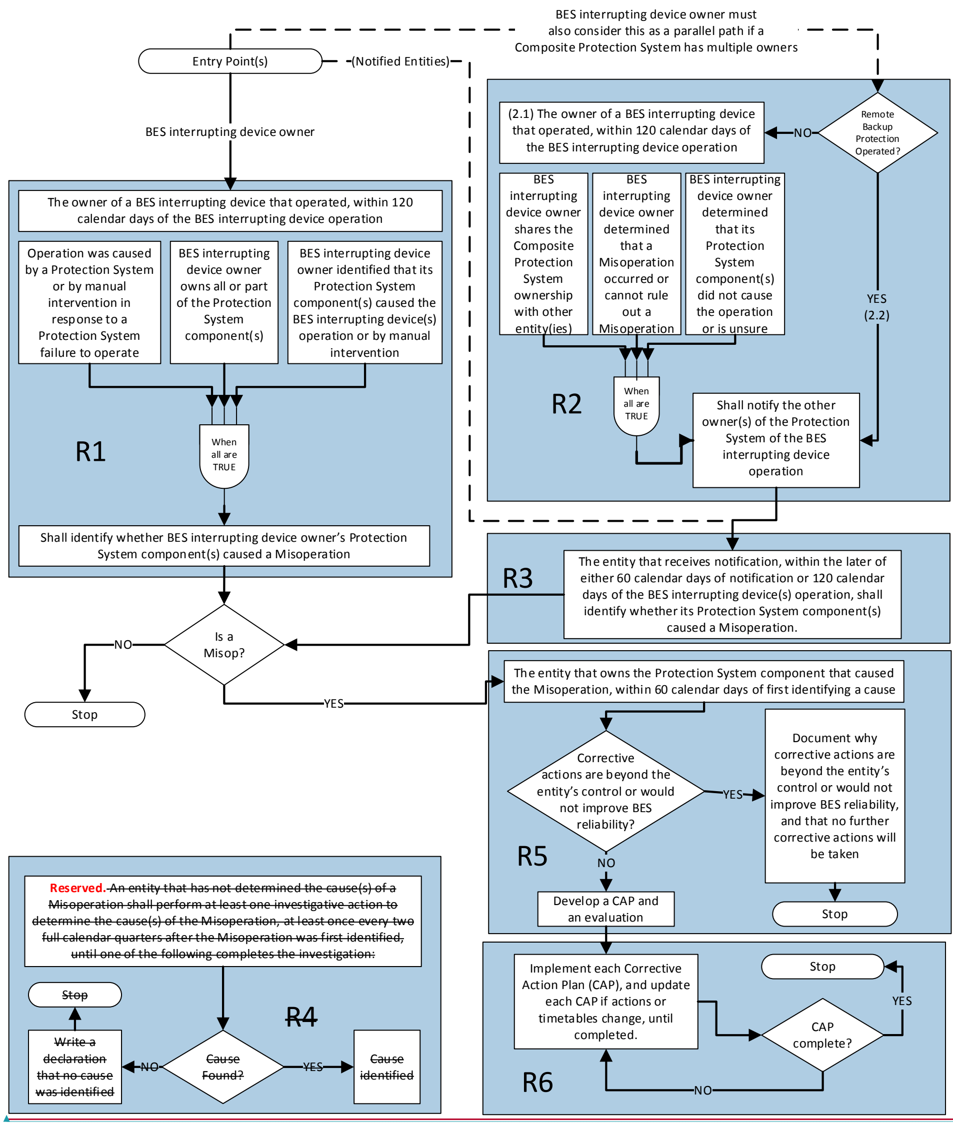
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Field Code Changed

~~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 Introduction~~

~~The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.~~

~~Rationale for Applicability~~

~~Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for "common- mode failure" type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.~~

A. Introduction

1. **Title:** Transmission Operations

2. **Number:** TOP-001-5

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. Reserved.

M19. Reserved.

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. Reserved.

M22. Reserved.

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 R18, and Measure M15 through M18 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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 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	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	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	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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	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 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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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. Reserved.				
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	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
			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 exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days	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	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	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

R #	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.	redundant functionality in more than 4 hours and less than or equal to 6 hours.	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 at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Authority's primary Control Center, 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 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	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	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	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; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	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 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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

Guidelines and Technical Basis

None.

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the [Project 2014-03] and [Project 2016-01] pages.

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):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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-001-45
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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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. Reserved. ~~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~~R18, and Measure M15 through ~~M19~~ M18 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Operator of its inability to comply with an Operating 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.
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	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	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	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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	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.	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.	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.	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 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	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	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,	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,

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.	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.	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.	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 required or identified as necessary by the Transmission	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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 any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	for one 30-minute period within that 24-hour period.	minute periods within that 24-hour period.		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.
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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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. Reserved.	~~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~~	~~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.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~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 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	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;	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;	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

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 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 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.	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 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 restore the redundant functionality.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R22. Reserved.	~~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.

R #	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	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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	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.			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
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	Requirements R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements

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 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 project page and the Project 2016-01 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.~~ [Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

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:

[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

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:** Voltage and Reactive Control

2. **Number:** VAR-001-6

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

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

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.

M2. Reserved.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the

associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to

the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:
"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. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.						
R3.	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to “area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	TBD	Adopted by the NERC Board of Trustees	Requirement R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R3:

The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate

granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a “tolerance band” as specified in the voltage schedule and the control dead-band in the generator’s excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator’s facility during normal operations, and be based on the TOP’s assessment of N-1 and credible N-2 system contingencies. The voltage schedule’s bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator’s automatic voltage regulator’s control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule’s bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-~~5~~6
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators
   - **4.2.** Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:** ~~The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~See Implementation Plan.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Reserved.~~Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*~~

M2. Reserved. ~~Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.~~

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 and M3 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“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. Additional Compliance Information:
None.

Violation Severity Levels

R #	Time Hori	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Operations Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2. Reserved.	~~**Real-time Operations, Same-day Operati**~~	~~**High**~~	~~N/A~~	~~N/A~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.~~	~~The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.~~
R3.	**Real-time Operations, Same-day Operations**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

Formatted Table

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5.	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6.	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

M.E.A.17 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

Page 12 of

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR- 001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	

Version	Date	Action	Change Tracking
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 "Area" was changed to "area."; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing "shall" with "will"; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.
5	10/15/2018	FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.	
6	TBD	Adopted by the NERC Board of Trustees	Requirement R2 Retired under Project 2018-03 Standard Efficiency Review Retirements

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

~~**Rationale for R2:**~~

~~Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.~~

Rationale for R3:

~~Similar to Requirement R2, t~~The VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Page 16 of

Rationale for R4:
The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:
The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:
Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Page 17 of

A. Introduction

1. **Title:** **Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M4. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning 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 Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired- Retirement approved by FERC effective January 21, 2014.)

- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods 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 Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3 (Retirement approved by FERC effective January 21, 2013.)	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF’s for Requirements R1. and R4. be changed from “Lower” to “Medium.” FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: FAC-013-2 — Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
FAC-013-2	R1.	04/01/2013		
FAC-013-2	1.1.	04/01/2013		
FAC-013-2	1.2.	04/01/2013		
FAC-013-2	1.3.	04/01/2013		
FAC-013-2	1.4.	04/01/2013		
FAC-013-2	1.4.1.	04/01/2013		
FAC-013-2	1.4.2.	04/01/2013		
FAC-013-2	1.4.3.	04/01/2013		
FAC-013-2	1.4.4.	04/01/2013		
FAC-013-2	1.4.5.	04/01/2013		
FAC-013-2	1.4.6.	04/01/2013		
FAC-013-2	1.4.7.	04/01/2013		
FAC-013-2	1.5.	04/01/2013		
FAC-013-2	R2.	04/01/2013		
FAC-013-2	2.1.	04/01/2013		
FAC-013-2	2.1.1.	04/01/2013		
FAC-013-2	2.1.2.	04/01/2013		
FAC-013-2	2.2.	04/01/2013		
FAC-013-2	R3.	04/01/2013		01/21/2014
FAC-013-2	R4.	04/01/2013		
FAC-013-2	R5.	04/01/2013		
FAC-013-2	R6.	04/01/2013		

A. Introduction

1. **Title:** **Dynamic Transfers**

2. **Number:** INT-004-3.1

3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Purchasing-Selling Entity

5. **Effective Date:**

   See implementation plan.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

[1] Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority 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 Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

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	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services	Attaining BA	Native BA

FERC OATT Schedules 3–6 and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

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 R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

3	June 30, 2014	FERC letter order issued approving INT-004-3	
3.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
3.1	November 26, 2014	FERC letter order approving errata changes.	

* FOR INFORMATIONAL PURPOSES ONLY *

Effective Date of Standard: INT-004-3.1 — Dynamic Transfers

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
INT-004-3.1	All	11/26/2014		

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2.1**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority

5. **Effective Date:**

   See implementation plan.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority 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 Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

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 R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised
2	June 30, 2014	FERC letter order issued approving INT-010-2	
2.1	August 22, 2014	Errata submitted for INT-004-3, INT-009-2, INT-010-2 and INT-011-2 to correct inconsistency between the Implementation Plan and the effective date language. The NERC Standards Committee approved errata changes on August 20, 2014.	Errata
2.1	November 26, 2014	FERC letter order approving errata changes.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: INT-010-2.1 — Interchange Initiation and Modification for Reliability

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
INT-010-2.1	All	11/26/2014		

A. Introduction

1. **Title:** **Available Transmission System Capability**
2. **Number:** **MOD-001-1a**
3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
   - **4.2.** Transmission Operator.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall select one of the methodologies[1] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*[*Time Horizon: Operations Planning*]

R2.1. Hourly values for at least the next 48 hours.

R2.2. Daily values for at least the next 31 calendar days.

R2.3. Monthly values for at least the next 12 months (months 2-13).

R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3.1. Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:

---

[1] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

R3.2.2. A rationale for that accounting specified in R3.2.

R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

R3.4. The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

R3.6.3. How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4.1. Each Planning Coordinator associated with the Transmission Service Provider's area.

R4.2. Each Reliability Coordinator associated with the Transmission Service Provider's area.

R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.

R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.

R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

R8.2. Daily values, once per day.

R8.3. Monthly values, once per week.

R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

R9.1. The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

C. Measures

M1. The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

M2. The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

M3. The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

M4. The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

M5. The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

M6. The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning.

When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

M7. The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

M8. The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

M9. The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider 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 Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.

- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.
R2.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours. ▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours. ▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours. ▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours. ▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days. ▪ Has calculated monthly ATC or AFC values for less than the next 4 months. ▪ Did not use the selected methodology(ies) to calculate ATC.
R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago. **OR** The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago. **OR** The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation. **OR** The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation.
R5.	N/A	N/A	N/A	The Transmission Service Provider did not make the ATCID available to the parties described in R4.
R6.	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	than 3 ATC Paths or Flowgates (whichever is greater).
R8.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R9	N/A	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request.	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request.	The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request.

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by the Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R2 and R8	Interpretation (Project 2009-15)
1a	1/14/2016	Corrected VRF designations from Lower to Medium for the following requirements based on Docket No. RM08-19-002: R1, R2, R3, R6, R7, R8, R9	

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the "advisory ATC" used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of "advisory" calculations in the responsible entity's Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific "ATC Paths." The NERC definition of ATC Path is "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path." Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO's "advisory ATC" is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. The second part of NYISO's question is only applicable if the first part was answered in the

negative and therefore will not be addressed.
Requirement Number and Text of Requirement

MOD-029-01 Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff." PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.
Question #2
Could OS_F in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?
Response to Question #2
This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-001-1a — Available Transmission System Capability

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-001-1a	All	04/01/2011		

A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

4. **Applicability:**

   4.1. Load-Serving Entities.

   4.2. Resource Planners.

   4.3. Transmission Service Providers.

   4.4. Balancing Authorities.

   4.5. Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-term Planning*]

R1.1. The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.

R1.2. The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.

R1.3. The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.

R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3. Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Medium]* [*Time Horizon: Operations Planning*]

R3.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R3.2. Identifying expected import path(s) or source region(s).

R4. Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R4.1. Using one or more of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R4.2. Identifying expected import path(s) or source region(s).

R5. At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R5.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area

- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R5.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

R6. At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]

R6.1. Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

R6.2. Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

R7. Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R8. Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

R9.1. Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.

R9.2. To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.

R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations*]

R11. When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12. The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity[1]" under an EEA 2 if: [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

R12.1. The CBM is available

R12.2. The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and

R12.3. The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.

C. Measures

M1. Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

M2. Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

---

[1] See Attachment 1-EOP-002-0 for explanation.

M3. Each Load-Serving Entity that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

M4. Each Resource Planner that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

M5. Each Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (R5)

M6. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years two through ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement. (Note that CBM values may legitimately be zero.) (R6)

M7. Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside. (R7)

M8. Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside. (R8)

M9. Each Transmission Service Provider that maintains CBM and each Transmission Planner shall provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R9. (R9)

M10. Each Load-Serving Entity and Balancing Authority shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time it requested to import energy using firm Transfer Capability set aside as CBM, it was in an EEA 2 or higher. (R10)

M11. Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived Real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R11)

M12. Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange meeting the criteria in R12. (R12)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force during the past three calendar years plus the current year to show compliance with R1.
- The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, R5, R7, R9, and R12 for the most recent three calendar years plus the current year.
- The Load-Serving Entity shall each maintain evidence to show compliance with R3 and R10 for the most recent three calendar years plus the current year.
- The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R6, R8, and R9 for the most recent three calendar years plus the current year.
- The Balancing Authority shall maintain evidence to show compliance with R10 and R11 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
- If an entity 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 subsequently submitted audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting

- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address one of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago. **OR** The CBM maintaining Transmission Service Provider's CBMID does not address two of the sub requirements.	The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago. **OR** The Transmission Service Provider that maintains CBM does not have a CBMID; **OR** The CBM maintaining Transmission Service Provider's CBMID does not address three of the sub requirements.
R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID after the effective date of the change, but not more than 30 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 30 or more calendar days but not more than 60 calendar days after the effective date of the change.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 60 or more calendar days but not more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to at least one, but not all, of the entities specified in R2.	The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID more than 90 calendar days after the effective date of the change. **OR** The Transmission Service Provider that maintains CBM made available the CBMID to none of the entities specified in R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.		The Load-Serving Entity did not use one of the methods described in R3.1 **OR** The Load-Serving Entity did not identify paths or regions as described in R3.2		The Load-Serving Entity did not use one of the methods described in R3.1 **AND** The Load-Serving Entity did not identify paths or regions as described in R3.2
R4		The Resource Planner did not use one of the methods described in R4.1 **OR** The Resource Planner did not identify paths or regions as described in R4.2		The Resource Planner did not use one of the methods described in R4.1 **AND** The Resource Planner did not identify paths or regions as described in R4.2
R5.	The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available. **OR** The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as	The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established. **OR** The Transmission Service Provider that maintains CBM failed to establish an initial value for CBM. **OR** The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		described in R5.2.		paths or regions as described in R5.2
R6.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 13 months, but not more than 16 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 16 months, but not more than 19 months, after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 19 months, but not more than 22 months, after the last time the values were established.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM for each of the years 2 through 10 more than 22 months after the last time the values were established. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM failed to establish an initial value for CBM for each of the years 2 through 10. **OR** The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		on one or more paths or regions as described in R6.2		R6.1 that was available, and did not base the allocation on one or more paths or regions as described in R6.2
R7.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Service Provider that maintains CBM notified none of the entities as required.
R8.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days. **OR** The Transmission Planner with	The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, **OR** The Transmission Planner with an associated Transmission

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			an associated Transmission Service Provider that maintains CBM notified at least one, but not all, of the entities as required.	Service Provider that maintains CBM notified none of the entities as required.
R9.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 30, but not more than 45, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 45, but not more than 60, days after the submission of the request.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 60, but not more than 75, days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided at least one, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.	The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 75 days after the submission of the request. **OR** The Transmission Service Provider or Transmission Planner provided none of the requesters specified in R9 with the supporting data, including models, used to allocate CBM.
R10.	N/A	N/A	N/A	A Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher.
R11.	N/A	N/A	N/A	A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The Transmission Service Provider failed to approve an Arranged Interchange for CBM that met the criteria described in R12 without a reliability reason to do so.

Version History

Version	Date	Action	Change Tracking
1	February 28, 2014	Updated VRF designations for Requirements R3 and R4 from Lower to Medium based on June 24, 2013 approval.	
1	January 14, 2016	Corrected VRF designations from Lower to Medium for the following requirements based FERC Letter Order dated June 24, 2013: R1, R2, R5, R6, R7	

* FOR INFORMATIONAL PURPOSES ONLY *

Effective Date of Standard: MOD-004-1 — Capacity Benefit Margin

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-004-1	All	04/01/2011		

A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R1.1. Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions).
- Reserve sharing requirements.
- Inertial response and frequency bias.

R1.2. The description of the method used to allocate TRM across ATC Paths or Flowgates.

R1.3. The identification of the TRM calculation used for the following time periods:

R1.3.1. Same day and real-time.

R1.3.2. Day-ahead and pre-schedule.

R1.3.3. Beyond day-ahead and pre-schedule, up to thirteen months ahead.

R2. Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R3. Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

R4. Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

R5. The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

C. Measures

M1. Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

M2. Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

M3. Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

M4. Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

M5. Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator 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 Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity 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.

1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.	The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago. **OR** The Transmission Operator's TRMID does not address one of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago. **OR** The Transmission Operator's TRMID does not address two of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3	The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more. **OR** The Transmission Operator does not have a TRMID. **OR** The Transmission Operator's TRMID does not address three of the following: ▪ R1.1 ▪ R1.2 ▪ Any one or more of the following: o R1.3.1, R1.3.2 or R1.3.3
R2.	N/A	N/A	N/A	One or both of the following: ▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. ▪ The Transmission Operator included components of CBM in TRM.
R3.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.	The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.	The Transmission Operator did not make the TRMID available for 90 days or more.

R4	The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing.	The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not establish TRM OR The last determination of TRM was more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.
R5	The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.	The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing.

Version History

Version	Date	Action	Change Tracking
1	November 24, 2009	MOD-008-1 approved by FERC	
1	January 14, 2016	Corrected VRF designations from Lower to Medium for the following: R1, R2, R4, and R5	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-008-1 — Transmission Reliability Margin Calculation Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-008-1	All	04/01/2011		

A. Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators**

2. **Number:** MOD-020-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-020-0 — Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-020-0	All	06/18/2007		

A. Introduction

1. Title: Area Interchange Methodology

2. Number: MOD-028-2

3. Purpose: To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. Applicability:

4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. Proposed Effective Date: In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

R1.3. Any contractual obligations for allocation of TTC.

R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.

R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:

R1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

R1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

R1.5.3. The source/sink or POR/POD identification and mapping to the model.

R1.5.4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

R2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R3.1. For TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. A daily or hourly load forecast for TTCs used in current-day and next-day ATC calculations.

R3.1.3. A daily load forecast for TTCs used in ATC calculations for days two through 31.

R3.1.4. A monthly load forecast for TTCs used in ATC calculations for months two through 13 months TTCs.

R3.1.5. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4.1. Use all Contingencies meeting the criteria described in the ATCID.

R4.2. Respect any contractual allocations of TTC.

R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.

R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

R6.3. Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: *Lower*] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$\mathbf{Postbacks_{NF}}$ are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$\mathbf{counterflows_{NF}}$ are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

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.

The Transmission Operator and Transmission Service Provider 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 Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator 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 Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider has an ATCID but it is missing one of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing two of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing more than three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	One or both of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.	One or more of the following: • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period • The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.	daily ATC calculations. • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R9.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 25% of the value calculated in the measure or 25MW, whichever is greater.	more than 35% of the value calculated in the measure or 35MW, whichever is greater.	more than 45% of the value calculated in the measure or 45MW, whichever is greater.	
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the Board of Trustees	
1	July 24, 2013	Updated VSLs based on June 24, 2013 approval.	
2	February 9, 2012	Adopted by the Board of Trustees	
2	July 24, 2013	FERC order issued July 18, 2013 approving MOD-028-2	

* FOR INFORMATIONAL PURPOSES ONLY *

Effective Date of Standard: MOD-028-2 — Area Interchange Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-028-2	All	10/01/2013		

A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-2a**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-2a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider 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 Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	11/05/2009	Board approved Interpretation of R5 and R6	Interpretation (Project 2009-15)
1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
2a	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
2a	November 19, 2015	FERC Order issued approving MOD-029-2a. Docket No. RM15-13-000.	

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.

The second part of NYISO's question is only applicable if the first part was answered in the negative and therefore will not be addressed.
Requirement Number and Text of Requirement

MOD-029-2a Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff." PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.
Question #2
Could OS_F in MOD-029-2a Requirement R5 and OS_{NF} in MOD-029-2a Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?
Response to Question #2
This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-029-2a — Rated System Path Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-029-2a	All	04/01/2017		

A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-3**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.

   4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:

R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

R1.2.3. The source/sink or POR/POD identification and mapping to the model.

R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.2. Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.3. Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

R2.2. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

R2.3. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

R2.4. Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

R2.5. At a minimum, establish the TFC once per calendar year.

R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

R3.3. Updated at least once per month for AFC calculations for months two through 13.

R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:

R6.2.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.7. The impact of other firm services determined by the Transmission Service Provider.

R7. When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.7. The impact of other non-firm services determined by the Transmission Service Provider.

R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

$Postbacks_{Fi}$ are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{Fi}$ are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

R11. When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \ldots PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

$PATC_n$ is the partial Available Transfer Capability for a path relative to a Flowgate *n.*

AFC_n is the Available Flowgate Capability of a Flowgate *n*.

DF_{np} is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

M5. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

M13. The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider 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 Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator 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.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. **OR** The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: • The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not	One or more of the following: • The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.	One or more of the following: • The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2. • The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.	One or more of the following: • The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2. • The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. • The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	been more than 14 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.	• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.	The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update. • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.	flowgate as described in R2.3. • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. • The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. • The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	One or more of the following: • The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days • The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks	One or more of the following: • The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days • The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks	One or more of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks	One or more of the following: • The Transmission Operator did not update the model per R3.2 for more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than ten weeks • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. • The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.
R4.	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calculated in the measure or 25MW, whichever is greater..	calculated in the measure or 35MW, whichever is greater.	calculated in the measure or 45MW, whichever is greater.	
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Flowgates or 1 Flowgate (whichever is greater).	or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	Flowgates or more than 3 Flowgates (whichever is greater).
R10	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.

A. Regional Differences

None identified.

B. Associated Documents

Version History

Version	Date	Action	Change Tracking
2		Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11	Revised
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving MOD-030-3. Docket No. RM15-13-000.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-030-3 — Flowgate Methodology

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-030-3	All	04/01/2017		

A. Introduction

1. **Title:** Available Transmission System Capability

2. **Number:** MOD-001-2

3. **Purpose:**

   To ensure that determinations of available transmission system capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1 Transmission Operator

   4.1.2 Transmission Service Provider

   4.2. Exemptions: The following is exempt from MOD-001-2.

   4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

5. **Effective Date:**

   5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1 Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:

1.1.1 Facility ratings;

1.1.2 System voltage limits;

1.1.3 Transient stability limits;

1.1.4 Voltage stability limits; and

1.1.5 Other System Operating Limits (SOLs).

1.2 Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:

1.2.1 The simulation of transfers performed through the adjustment of generation, Load, or both;

1.2.2 Transmission topology, including, but not limited to, additions and retirements;

1.2.3 Expected transmission uses;

1.2.4 Planned outages;

1.2.5 Parallel path (loop flow) adjustments;

1.2.6 Load forecast; and

1.2.7 Generator dispatch, including, but not limited to, additions and retirements.

1.3 Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe in its methodology the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operator's area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
  - TFC or TTC being determined by one or more limits.
  - Simulation being used to find the maximum TFC or TTC that remains within the limit.
  - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
  - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
  - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
  - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
  - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
  - A description of how the element is used in the determination of TFC or TTC.
- A description of the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, as specified in parts 1.3, 1.3.1, 1.3.2, or 1.3.3).
- Each Transmission Operator that determines TFC or TTC shall provide evidence that currently active TFC or TTC values were determined based on its current written methodology, as specified in Requirement R1.

R2. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC:

2.1.1. The simulation of transfers performed through the adjustment of generation, Load, or both;

2.1.2. Transmission topology, including, but not limited to, additions and retirements;

2.1.3. Expected transmission uses;

2.1.4. Planned outages;

2.1.5. Parallel path (loop flow) adjustments;

2.1.6. Load forecast; and

2.1.7. Generator dispatch, including, but not limited to, additions and retirements.

2.2. Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

M2. Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:

- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
  - A description of how the element is used in the determination of AFC or ATC.
  - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
  - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- For each Transmission Service Provider that uses the Flowgate Methodology, a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability-related constraints identified in part 1.3.
- Each Transmission Service Provider that determines AFC or ATC shall provide evidence that currently active AFC or ATC values were determined based on its current written methodology, as specified in Requirement R2.

R3. Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for determining CBM values. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

R4. Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for determining TRM values. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values. *[Violation Risk Factor: Lower][Time Horizon: Operations Planning]*

M4. Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Operator does not maintain TRM.

R5. Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

5.1. A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

5.2. If not publicly posted on OASIS or its company website, the Transmission Operator's effective:

5.2.1 TRMID; and

5.2.2 TFC or TTC methodology.

5.3. If not publicly posted on OASIS or its company website, the Transmission Service Provider's effective:

5.3.1 ATCID; and

5.3.2 CBMID.

M5. Examples of evidence include, but are not limited to:

- Dated records of the request and the Transmission Operator's or Transmission Service Provider's response to the request;
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

R6. Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

6.1.1 Alter the format in which it maintains or uses the data; or

6.1.2 Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.

6.3 If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or

- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) is a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
    - Hourly values for the most recent 14 days;
    - Daily values for the most recent 30 days; and
    - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- "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. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	**Operations Planning**	**Lower**	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1) OR Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2) OR	Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values. OR Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator's TFC or TTC calculation and the request referenced part 1.3. (1.3) OR Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	**Operations Planning**	**Lower**	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	**Operations Planning**	**Lower**	None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	None.	None.	None.	Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values. OR Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.
R5	**Operations Planning**	**Lower**	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the date of the request, but did respond in writing within 75 calendar days.	the date of the request, but did respond in writing within 105 calendar days.	from the date of the request, but did respond in writing within 135 calendar days.	
R6	**Operations Planning**	**Lower**	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

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 R1:

Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability-related constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.

Rationale for R2:

A TSP must clearly document its methods of determining AFC and ATC so that TOPs or other entities can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate. Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC.

Rationale for R3:

Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose Loads are located on that TSP's system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

Rationale for R4:

Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC and ATC is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of determining TRM.

Rationale for R5:

Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Rationale for R6:

This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP or TSP share their data, with the caveat that the TOP or TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP or TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board of Trustees.	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	February 6, 2014	Adopted by the NERC Board of Trustees.	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: MOD-001-2 — Available Transmission System Capability

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
MOD-001-2	All			

This standard has not yet been approved by the applicable regulatory authority.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2018-03 Standards Efficiency Review Retirements

Applicable Standard(s)

- FAC-008-4 – Facility Ratings
- INT-006-5 – Evaluation of Interchange Transactions
- INT-009-3 – Implementation of Interchange
- IRO-002-7 – Reliability Coordination – Monitoring and Analysis
- PRC-004-6 – Protection System Misoperation Identification and Correction
- TOP-001-5 – Transmission Operations
- VAR-001-6 – Voltage and Reactive Control

Requested Retirement(s)

- FAC-008-3 – Facility Ratings
- FAC-013-2 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- INT-004-3.1 – Dynamic Transfers
- INT-006-4 – Evaluation of Interchange Transactions
- INT-009-2.1 – Implementation of Interchange
- INT-010-2.1 – Interchange Initiation and Modification for Reliability
- IRO-002-6 – Reliability Coordination – Monitoring and Analysis
- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Readability Margin Calculation Methodology
- MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
- MOD-028-2 – Area Interchange Methodology
- MOD-029-2a – Rated System Path Methodology
- MOD-030-3 – Flowgate Methodology
- PRC-004-5(i) – Protection System Misoperation Identification and Correction
- TOP-001-4– Transmission Operations
- VAR-001-5– Voltage and Reactive Control

Requested Withdrawal

- MOD-001-2 – Available Transmission System Capability

Applicable Entities

See subject standards.

Background

In 2017, NERC initiated the Standards Efficiency Review. The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. Following the completion of the first phase of work, the Standards Efficiency Review Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- withdraw a standard, MOD-001-2, that is currently pending approval by applicable governmental authorities.

General Considerations

For Reliability Standards that are proposed to be retired in their entirety (i.e., no new standard version is proposed), this Implementation Plan provides that the retirement shall become effective immediately upon regulatory approval.

For Reliability Standards that are revised to remove requirements, the revised standards will become effective on the first day of the first calendar quarter that is three (3) months after applicable regulatory approval. This implementation timeframe reflects consideration that entities may need time to update their internal systems and documentation to reflect the new standard version numbers.

Effective Date

Reliability Standards FAC-008-4, INT-006-5, INT-009-3, IRO-002-7, PRC-004-6, TOP-001-5, and VAR-001-6

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 (3) 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 (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standards FAC-008-3, INT-006-4, INT-009-2.1, IRO-002-6, PRC-004-5(i), TOP-001-4, and VAR-001-5

The Reliability Standard shall be retired immediately prior to the effective date of the revised standard in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standards FAC-013-2, INT-004-3.1, INT-010-2.1, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-020-0, MOD-028-2, MOD-029-2a, and MOD-030-3

The Reliability Standard shall be retired on the effective date of the applicable governmental authority's order approving retirement of 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 be retired on the date the standard is retired by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2018-03 Standards Efficiency Review Retirements

Applicable Standard(s)

- FAC-008-4 – Facility Ratings
- INT-006-5 – Evaluation of Interchange Transactions
- INT-009-3 – Implementation of Interchange
- IRO-002-~~6~~ 7 – Reliability Coordination – Monitoring and Analysis
- PRC-004-6 – Protection System Misoperation Identification and Correction
- TOP-001-5 – Transmission Operations
- VAR-001-6 – Voltage and Reactive Control

Requested Retirement(s)

- FAC-008-3 – Facility Ratings
- FAC-013-2 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- INT-004-3.1 – Dynamic Transfers
- INT-006-4 – Evaluation of Interchange Transactions
- INT-009-2.1 – Implementation of Interchange
- INT-010-2.1 – Interchange Initiation and Modification for Reliability
- IRO-002-~~5~~ 6 – Reliability Coordination – Monitoring and Analysis
- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Readability Margin Calculation Methodology
- MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
- MOD-028-2 – Area Interchange Methodology
- MOD-029-2a – Rated System Path Methodology
- MOD-030-3 – Flowgate Methodology
- PRC-004-5(i) – Protection System Misoperation Identification and Correction
- TOP-001-4– Transmission Operations
- VAR-001-5– Voltage and Reactive Control

Requested Withdrawal

- MOD-001-2 – Available Transmission System Capability

Applicable Entities

See subject standards.

Background

In 2017, NERC initiated the Standards Efficiency Review. The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. Following the completion of the first phase of work, the Standards Efficiency Review Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- withdraw a standard, MOD-001-2, that is currently pending approval by applicable governmental authorities.

General Considerations

For Reliability Standards that are proposed to be retired in their entirety (i.e., no new standard version is proposed), this Implementation Plan provides that the retirement shall become effective immediately upon regulatory approval.

For Reliability Standards that are revised to remove requirements, the revised standards will become effective on the first day of the first calendar quarter that is three (3) months after applicable regulatory approval. This implementation timeframe reflects consideration that entities may need time to update their internal systems and documentation to reflect the new standard version numbers.

Effective Date

Reliability Standards FAC-008-4, INT-006-5, INT-009-3, IRO-002-~~6~~7, PRC-004-6, TOP-001-5, and VAR-001-6

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 (3) 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 (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standards FAC-008-3, INT-006-4, INT-009-2.1, IRO-002-~~5~~6, PRC-004-5(i), TOP-001-4, and VAR-001-5
The Reliability Standard shall be retired immediately prior to the effective date of the revised standard in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standards FAC-013-2, INT-004-3.1, INT-010-2.1, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-020-0, MOD-028-2, MOD-029-2a, and MOD-030-3
The Reliability Standard shall be retired on the effective date of the applicable governmental authority's order approving retirement of 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 be retired on the date the standard is retired by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard FAC-008-4. 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.

VRF Justification for FAC-008-4, Requirement R1

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R2

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R3

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R6

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R1

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R2

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R3

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R6

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard FAC-008-4. 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.

VRF Justification for FAC-008-4, Requirement R1

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R2

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R3

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R6

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R1

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R2

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R3

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R6

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-006-5. 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.

VRF Justification for INT-006-5, Requirement R1

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R2

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R3

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R1

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R2

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R3

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard, with the exception of: the reference to communicating a fact within 10 minutes of the denial was deleted to correspond to the retirement of Requirement R3 Part 3.1.

VSLs for INT-006-5, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-006-5. 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.

VRF Justification for INT-006-5, Requirement R1

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R2

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VRF Justification for INT-006-5, Requirement R3

The VRF did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R1

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R2

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard.

VSL Justification for INT-006-5, Requirement R3

The VSL did not change from the previously FERC approved INT-006-4 Reliability Standard, with the exception of: the reference to communicating a fact within 10 minutes of the denial was deleted to correspond to the retirement of Requirement R3 Part 3.1.

VSLs for INT-006-5, Requirement R3			
Lower	Moderate	High	Severe
N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-009-3. 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.

VRF Justification for INT-009-3, Requirement R1

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VRF Justification for INT-009-3, Requirement R3

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R1

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R3

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard INT-009-3. 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.

VRF Justification for INT-009-3, Requirement R1

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VRF Justification for INT-009-3, Requirement R3

The VRF did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R1

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

VSL Justification for INT-009-3, Requirement R3

The VSL did not change from the previously FERC approved INT-009-2.1 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard IRO-002-7. 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.

VRF Justification for IRO-002-7, Requirement R2

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R3

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R4

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R5

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-7, Requirement R6

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R2

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R3

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R4

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R5

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-7, Requirement R6

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard IRO-002-~~6~~7. 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.

VRF Justification for IRO-002-~~6~~7, Requirement R2

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-~~6~~7, Requirement R3

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-~~6~~7, Requirement R4

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-~~6~~7, Requirement R5

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VRF Justification for IRO-002-~~6~~7, Requirement R6

The VRF did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-~~6~~7, Requirement R2

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-~~6~~7, Requirement R3

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-~~6~~7, Requirement R4

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-~~6~~7, Requirement R5

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

VSL Justification for IRO-002-~~6~~7, Requirement R6

The VSL did not change from the previously FERC approved IRO-002-5 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard PRC-004-6. 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.

VRF Justification for PRC-004-6, Requirement R1

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R2

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R3

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R5

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R6

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R1

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R2

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R3

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R5

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R6

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard PRC-004-6. 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.

VRF Justification for PRC-004-6, Requirement R1

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R2

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R3

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R5

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VRF Justification for PRC-004-6, Requirement R6

The VRF did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R1

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R2

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R3

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R5

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

VSL Justification for PRC-004-6, Requirement R6

The VSL did not change from the previously FERC approved PRC-004-5(i) Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard TOP-001-5. 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.

VRF Justification for TOP-001-5, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R6

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R7

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R8

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R9

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R10

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R2
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard TOP-001-5. 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.

VRF Justification for TOP-001-5, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R6

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R7

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R8

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R9

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R10

The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VRF Justification for TOP-001-5, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R2
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

VSL Justification for TOP-001-5, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard VAR-001-6. 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.

VRF Justification for VAR-001-6, Requirement R1

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R3

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R4

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R5

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R6

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R1

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R3

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R4

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R5

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R6

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in proposed Reliability Standard VAR-001-6. 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.

VRF Justification for VAR-001-6, Requirement R1

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R3

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R4

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R5

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VRF Justification for VAR-001-6, Requirement R6

The VRF did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R1

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R3

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R4

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R5

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

VSL Justification for VAR-001-6, Requirement R6

The VSL did not change from the previously FERC approved VAR-001-5 Reliability Standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2018-03 - Standards Efficiency Review Retirements

Technical Justifications

Background:
The North American Electric Reliability Corporation (NERC) Project 2018-03 – Standards Efficiency Review (SER) Retirements, was established for the Standard Drafting Team (SDT) to evaluate each recommendation for retirement identified in the Standard Authorization Request (SAR).

The Reliability Standards have their origins in the voluntary consensus Operating Guides and Planning Standards. These original documents were modified into what we currently know as the "Version 0" standards. The objective of the added granularity to the requirements was to support the reliable operation of the Bulk Electric System (BES). These requirements were prescriptive, and meant to provide an industry-wide approach to achieving the reliability objectives of the standards. In the last 10 years, the industry has matured and adopted compliance through the Reliability Standards, and the continuance of the added granularity of the requirements do not contribute to the efficiency and effectiveness of Reliability Standards.

In 2010, NERC determined that absolute, "do exactly as the standard dictates" requirements, in some cases, did not satisfy the reliability goal and required the entity to perform specific actions to be compliant, while not effectively adding to the overall reliability goal. NERC then embarked on a shift in the standards paradigm to what is now known as 'results-based standards,' wherein the standards specify what reliability results from the requirements, while affording entities flexibility in achieving those results. The development guidance, provided by NERC, can be found at the following link:

https://www.nerc.com/pa/Stand/Resources/Documents/Results-Based_Reliability_Standard_Development_Guidance.pdf

Many of the requirements that the Project 2018-03 SDT are proposing to retire in this project pre-date the maturity of the results-based standards paradigm. As a result, those requirements are overly prescriptive and often express the same obligation in several standards and requirements.

Purpose:
The purpose of the Technical Justification Document is to assist in the understanding of the technical rationale associated with each recommendation for retirement identified in the SAR.

Technical Justifications for Phase I of Project 2018-03 Standards Efficiency Review - Retirements

BAL-005-1, Requirements R4 and R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain

Rationale
The SDT determined these requirements should be retained for the following reasons:

Requirements R4 and R6 of BAL-005-1 are requirements specific to the calculation of the Area Control Error (ACE). TOP-010-1(i) Requirement R2 covers ACE with the wording of "…analysis functions and Real-time monitoring…" but does not cover specifics, such as: quality flags for missing or invalid data that is part of BAL-005-1, Requirement R4, or the accuracy of scan rates that is part of BAL-005-1, Requirement R6.

In TOP-010-1(i), Requirement R2 (revised from TOP-010-1) covers the calculation and monitoring of ACE; however, the language: "Each Balancing Authority (BA) shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring," is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) Requirement R4 states: "The BA shall make available to the operator information associated with reporting ACE including, but not limited to, quality flags indicating missing or invalid data." Requirement R6 of BAL-005-1 states: "Each BA that is within a multiple BA Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each BA area." Both of these requirements are specific to identifying missing or invalid data plus scan rates, not just the quality of the Real-time data.

The SER Phase I team will communicate with the SER Phase II team regarding Requirements R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i), Requirement R2, that would satisfy the missing or invalid data plus scan rates. If the SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be candidates for retirement within that project or a future project.

COM-002-4, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding, and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005-2 would not meet the NERC Board of Trustees (BOT) November 7, 2013 Resolution to mandate training, that the SDT include a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity, and any subsequent training can be covered in PER-005-2, or through the operator feedback loop as determined by the entity.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2, Requirement R2 that would satisfy the training requirements specific to training on communications protocols. If the SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirement R2 of COM-002-4 may be a candidate for retirement within that project or a future project.

EOP-005-3, Requirement R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes; however, it is does not specifically provide for System restoration training. In PER-005-2, the requirement to provide System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to System restoration from PER-005-1 was, in part, based on the existence of the former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide System restoration training to operating personnel in any of the Reliability Standards.

A specific requirement for System restoration training should be maintained because, while a System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the SER Phase II team regarding Requirement R8 of EOP-005-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to System restoration training. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R8 of EOP-005-3 may be a candidate for retirement within that project or a future project.

EOP-006-3, Requirement R7
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes; however, it is does not specifically provide for System restoration training. In PER-005-2, the requirement to provide System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to System restoration from PER-005-1 was, in part, based on the existence of former Requirement R9 in EOP-006-2

(Requirement R7 of EOP-006-3). If Requirement R7 in EOP-006-3 is removed, then there will not be any requirements to provide System restoration training to operating personnel in any of the Reliability Standards.

A specific requirement for System restoration training should be maintained because, while a System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the SER Phase II team regarding Requirement R7 of EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to System restoration training. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R7 of EOP-006-3 may be a candidate for retirement within that project or a future project.

FAC-008-3, Requirements R7 and R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1, Requirement R2, the Transmission Owner (TO) and Generator Owner (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1, and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data includes facility ratings as inputs to System Operating Limits (SOL) monitoring. IRO-010-2, Requirement R3, and TOP-003-3, Requirement R5, require that the TO and the GO to respond to the RC's and the TOP's requests.

FAC-013-2 Requirements R1, R2, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

The requirement for PCs to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Assessing transfer capability above the “known commitments for Firm Transmission Service and Interchange” required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Individual PCs develop their own methodologies that may be disparate from each other.
- Impacted functional entities, such as the TP, do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable System performance is.
- Entities that receive the methodology or assessment results are not obligated to use or consider the information in their assessments.
- Requirement R4 only requires the assessment be performed for one year in the Near-Term Transmission Planning Horizon. The PC can arbitrarily choose this year, and the analysis does not guarantee transmission service that is necessary for System reliability.

Assessing transfer capability in the planning horizon is a method to test the robustness of the System. Robustness testing of a System is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment of it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by the Federal Energy Regulatory Commission (FERC) in 2014.

INT-004-3.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale

The SDT determined this standard should be retired for the following reasons:

INT-004-3.1 may be retired since it satisfies Paragraph 81 Criteria ‘B6 – Commercial or Business Practice.’ Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity (PSE), has been removed from the list of NERC Functional Entities, supporting the market-based observations herein. Requirement R3 specifically refers to “Pseudo-Ties that are included in the North American Energy Standards Board (NAESB) Electric Industry Registry,” reinforcing the tie to the NAESB Wholesale Electric Quadrant (WEQ) Business Practice Standards.

INT-006-4, Requirements R3.1, R4, and R5
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these requirements should be retired for the following reasons:

INT-006-4, Requirement R3 Part 3.1 can be retired under Paragraph 81, Criterion A. There is no substantive impact on reliability with requiring the RC to be notified when a Reliability Adjustment Arranged Interchange has been denied.

INT-006-4, Requirement R4 can be retired under Paragraph 81, Criteria A and B7. Covered in NAESB e-Tagging specifications, Section 1.6.3.1 and Section 1.3, Request State. This requirement outlines the conditions that must exist for an Arranged Interchange to transition to Confirmed Interchange. NAESB Electronic Tagging Specification Section 1.6.3.1 and Section 1.3, Request State, stipulate these exact requirements. INT-006-4, Requirement R4 is being recommended for retirement. The requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-006-4, Requirement R5 can be retired under Paragraph 81, Criteria A and B7. This is covered in NAESB e-Tagging specifications, Section 1.6.4. This requirement outlines who is notified when the transition to Confirmed Interchange occurs. NAESB Electronic Tagging Specification, Section 1.6.4, stipulate these exact requirements. INT-006-4, Requirement R5, is being recommended for retirement; the requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-009-2.1, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this requirement should be retired for the following reasons:

This requirement can be retired under Paragraph 81, Criterion B7. INT-009-2.1, Requirement R2, is redundant with the approved NERC Reliability Standard BAL-005-1, Requirement R7.

INT-010-2.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

The opportunity exists to retire Reliability Standard INT-010-2.1 in its entirety.

INT-010-2.1, Requirement R1: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R1 for retirement. More stringent tagging requirements already

exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R2: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R2 for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-8. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R3: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R3 for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5, Requirements R1, R4 and R6:
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R1, Retain Requirements R4 and R6
Rationale
The SDT determined that Requirement R1 should be retired for the following reasons:

Requirement R1 of IRO-002-5 is redundant to other requirements in the Interconnection Reliability Operations and Coordination (IRO) family of standards. Requirement R1 and data exchange for the Operational Planning Assessment (OPA) is inherent to Requirement R2 that has a higher Violation Risk Factor (VRF) and is tied to the OPA in IRO-010-2, Requirement R3. The requirement is a control for aiding compliance with IRO-008-2, Requirement R1, related to the performance of an OPA, and it is duplicative to Requirement R3 in IRO-010-2. The purpose statement of IRO-010-2 is for the RC: "To prevent instability, uncontrolled separation, or Cascading outages the adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area." The Purpose statement of IRO-008-2 is for the RC to: "Perform the analysis to prevent instability, uncontrolled separation, or Cascading" and with the data collected per IRO-010-2. The data exchange capabilities are indicated in IRO-010-2, Requirement R3, which includes BA's and TOPs, and IRO-008-2, Requirement R1, requires the RC to perform the OPA, which makes IRO-002-5, Requirement R1, redundant with the aforementioned standards and requirements.

IRO-010-2 (R1) requires the RC to identify the data it needs to perform its OPA's, Real-time monitoring, and Real-time Assessments. Requirement R1 clearly states what is required, 1.1 A list of data and information needed by the RC to support its OPA, Real-time monitoring, and Real-time assessments including non-BES data and external network data, as deemed necessary by the RC, 1.2 Provisions for notification of current Protection System and Special Protection Systems status or degradation that impacts System Reliability, 1.3 A periodicity for providing data, 1.4 The deadline by which the respondent is to provide the indicated data. Requirement R2 clearly states, "The RC shall distribute its data specifications to entities that have data required by the RC's OPAs, Real-time monitoring, and Real-time Assessments. Requirement R3 gets to the core of the data exchange capabilities "Each RC, BA, GO, GOP, Load-Serving Entity (LSE), TOP, TO, and Distribution Provider (DP) receiving a data specification in

Requirement R2 shall satisfy the obligations of the documented specifications using 3.1 A mutually agreeable format, 3.2 A mutually agreeable process for resolving data conflicts, 3.3 A mutually agreeable security protocol. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the OPA. Finally, Measure M1 for IRO-002-5, Requirement R1, states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the IRO-002-5, Requirement R1, is not needed to support reliability and can be retired.

The SDT determined that Requirements R4 and R6 should be retained for the following reasons:

IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

The requirements in IRO-010-2 shall satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via a redundant/secure communications, such as Inter Control Center Communication Protocol (ICCP), email, voltage schedules, outage scheduling that all RCs, BAs and TOPs use to exchange the required data.

IRO-008-2, Requirement R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

Although IRO-008-2, Requirement R6, appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6, is not being sought during this phase of the project.

IRO-014-3, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (Requirement R1, Part 1.1); this ensures RC operations are coordinated to maintain reliability of the BES. As such, a separate requirement for ensuring notifications are made to impacted RCs is duplicative. However, the IRO-014-3, Requirement R1, time horizon would need to be revised to a time horizon of "Real-time" if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3, is not being sought during this phase of the project.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R3 of IRO-014-3 to determine if there is opportunity for revision to IRO-014-3, Requirement R1, that would satisfy the revision of the time horizon to “Real-time.” If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R3 of IRO-014-3 may be a candidate for retirement within that project or within a future project.

IRO-017-1, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this requirement should be retained for the following reasons:

IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3, for retirement.

The SER Phase I team will communicate with the SER Phase II team regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TLP-001-4 that would satisfy the adding of the RC as a named recipient. If the SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R3 of IRO-017-1 may be a candidate for retirement within that project or within a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3, MOD-001-1a and proposed MOD-001-2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined these standards should be retired for the following reasons:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as e-Tags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time System operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the System to its actual reliability limits.

MOD-002-1: Entities are not required to determine Total Flowgate Capability (TFC), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), Available Transfer Capability (ATC), Capacity Benefit Margin (CBM), or Transmission Reliability Margin (TRM), therefore; this is a conditional obligation, and there is no requirement that entities coordinate their methodologies. A reliability-based requirement

would establish obligations to ensure consistency between entities' methodologies. These requirements are administrative in nature and have no performance measure.

Additionally, TOPs and/or TSPs are not obligated in any fashion to determine TFC, TTC, AFC, ATC, CBM or TRM, nor are any criteria established for these quantities. Therefore, the requirements here require that entities that use an optional mechanism with no related criteria provide a methodology document and associated implementation documents, with no criteria as to what those documents must include, rather than just their "methodology." That reinforces that these are all administrative documents with little (if any) reliability benefit.

Further, Requirement R3 establishes that the TSP develops CBM for the benefit of the LSE, which has been removed from the list of NERC Functional Entities.

Finally, Requirements R5 and R6, through their clear and focused references to Open Access Same-Time Information System (OASIS), further emphasize the commercial elements of these subjects, and that this information, shared with other market participants, may easily be subject to FERC transparency rules commonly known as FERC Standards of Conduct under Rule 888. The definition of AFC also explicitly contains the term, "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." This seems to leave little question about the market focus of particularly Flowgate Capability.

MOD-020-0, Requirement R1 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this standard should be retired for the following reasons:

MOD-031-2 and IRO-010-2 do not give the necessary entities the authority to request relevant information, nor does MOD-031-2 and IRO-010-2 require the associated entities to provide that information. Demand-Side Management (DSM) data may be related to the near-term operating time horizon and/or the planning time horizons, but not to the Real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4, Requirements R1 and R2, and IRO-001-4, Requirement R1, the RC, BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over DSM. They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4, Requirement R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0, Requirement R1, are sources of DADS data, have access to DADS data, or both.

DSM and Direct Control Load Management (DLCM) may be regarded as long-term planning and operations planning time horizon resources, but particularly with a "on request within 30 calendar days" obligation in the requirement, is not a resource for the Real-time or day-ahead operating time horizon for RCs and TOPs, which must plan to operate, and actually operate, the BES within SOL's and IROL's, a subset of SOLs. In addition, the amount of interruptible demands and DLCM at the TP, Resource Planner (RP), and/or LSE (which has been removed from the compliance registry and is no longer obligated to comply with NERC standards) level is not of locational benefit to TOPs and RCs to assist them in operating within SOL's, as such information, were it to be provided within a usable time frame, would not be sufficiently granular to assist the TOP and RC. All meaningful information regarding interruptible demands and DLCM is available from DADS, which in the United States (US), is a mandatory reporting mechanism, regulated per Section 1600 of the NERC Rules of Procedure. DSM and DLCM are financially-enabled mechanisms whereupon RPs may encourage customers and customer groups to permit local control of their load in exchange for rate considerations, and this local control may or may not be sited in such a manner to provide any benefit to TOP's and RC's; which, again, are obligated by NERC Standards to operate the BES within SOL's.

PRC-004-5(i), Requirement R4
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT determined this requirement should be retired for the following reasons:

The standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for BES Elements. The Reliability Standard's Guideline and Technical Basis for Requirement R4 considers due diligence that an entity must make in determining the cause of a Protection System Misoperation.

The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with Requirements R1 and R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a Misoperation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation, and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of Requirement R4 does not preclude the entity's responsibility to continue the investigation to identify the cause of Misoperations; however, it does alleviate the need to keep tracking documents for showing investigative actions.

PRC-015-1 Requirements R1, R2, and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this standard should be retained for the following reasons:

PRC-015-1 is scheduled to be retired on 12/31/2020 under the PRC-012-2 Implementation Plan (IP).

PRC-018-1 Requirements R1, R2, R3, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT determined this standard should be retained for the following reasons:

PRC-018-1 is superseded by PRC-002-2 in Year 2022. The PRC-002-2 IP states: "Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2…"

TOP-001-4 Requirements R16, R17, R19 and R22
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain Requirements R16 and R17, Retire Requirements R19 and R22
Rationale
The SDT determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator (SO) has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17, were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17, is not being sought during this phase of the project.

The purpose of TOP-003-3 is to ensure adequate data is collected by the BA and TOP to fulfill their operational and planning responsibilities. The purpose of TOP-002-4 is to ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22, for the BA and TOP are redundant with TOP-003-3, Requirements R3, R4 and R5, and TOP-002-4, Requirement R1.

The SDT determined Requirements R19 and R22 should be retired for the following reasons:

TOP-001-4, Requirement R19, is redundant to other requirements in the Transmission Operations (TOP) family of standards. For TOPs, the existing TOP-003-3, Requirement R5, cannot be fulfilled by entities unless data exchange capabilities exist between the TOP and the supplying entities. Similarly, TOP-002-4, Requirement R1, cannot be fulfilled by the TOP unless the data needed to perform the OPA has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R19 in TOP-001-4 is not needed to support reliability and can be retired.

TOP-001-4, Requirement R22, is redundant to other requirements in the TOP family of standards. For the

BA, the existing TOP-003-3, Requirement R5, cannot be fulfilled by entities unless data exchange capabilities exist between the BA and the supplying entities. Similarly, TOP-002-4, Requirement R4 cannot be fulfilled by the BA unless the data needed to develop its Operating Plan for next-day operations has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R22 in TOP-001-4 is not needed to support reliability and can be retired.

VAR-001-5*, Requirements R2 and R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R2, Retain Requirement R3
Rationale
The SDT determined Requirement R2 should be retired for the following reasons:

VAR-001-5, Requirement R2 states, "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load"

VAR-001-5, Requirement R2, contains two sentences, with the first sentence being a requirement and the second being a guidance statement. Each sentence is analyzed separately.

The first sentence requires the TOP to schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the OPA as described and required in TOP-002-4 and the criteria described in TOP-001-4, Requirement R10, the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis (RTCA) tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Additionally, the TOP uses Real-time monitoring, allowing it to make real-time decisions on voltage during normal conditions. These allow the TOP to quantify the use of reactive resources and makes VAR-001-5, Requirement R2, unnecessary.

Further to this requirement that a TOP have sufficient reactive resources, the planning standard TPL-001-4 requires the PA and TP to conduct studies on their transmission Systems to ensure it operates reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. These studies include available reactive resource capabilities. The studies provide corrective action plans (CAPs) when the analysis indicates an inability of the System to meet performance requirements. CAPs include, as necessary, the amount of reactive resource capabilities needed. This ensures that the TOP has available an adequate number of reactive resources to operate under normal contingency conditions.

TOP-002-4, Requirement R1, requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10, provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. The requirements in TOP-001-4 and TOP-002-4 direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-

5 requirements mandate that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The Facilities Design, Connections and Maintenance (FAC) family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and System ratings.

Specifically,

1. TOP-002-4 - Operations Planning with an effective date of April 1, 2017

   Requirement R1 of this standard requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOL's. Requirement R2 requires the TOP to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific System restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition; one such tool is reactive resources. The TOP must have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate or sufficient number is determined through analysis.

2. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement R13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes, and Requirement R14 requires the TOP to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

   This requirement, again, addresses that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of TOP exists here as it did under TOP-002-4; the TOP must have an adequate number of reactive resources to mitigate SOL exceedances. The adequate or sufficient number is determined through analysis.

The second sentence of VAR-001-5 R2 states: "Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As noted by the VAR Enhanced Periodic Review group during its September 2016 meeting, and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then, as well as now, that perhaps this language be moved to a guidance section or document.

The SDT determined that Requirement R3 should be retained for the following reasons:
For reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL to prevent voltage-collapse events wherein the operation within SOLs/IROLs itself is not adequate to assure stable voltage operations in both steady-state and transient

conditions. The TOP family of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary.

* VAR-001-4.2 is an inactive standard. VAR-001-5 changed the Western Electricity Coordinating Council (WECC) variance, and not the continent-wide requirements. VAR-001-5 became effective January 1, 2019.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2018-03 - Standards Efficiency Review Retirements

Technical Justifications

Background:

The North American Electric Reliability Corporation (NERC) ~~Purpose: The purpose of the~~ Project 2018-03 – Standards Efficiency Review (SER) Retirements ~~Technical Justifications document~~, was established for the ~~Standards~~Standard Drafting Team (SDT) to evaluate each recommendation for retirement identified in the ~~Standards~~Standard Authorization Request (SAR). ~~It~~

The Reliability Standards have their origins in the voluntary consensus Operating Guides and Planning Standards. These original documents were modified into what we currently know as the "Version 0" standards. The objective of the added granularity to the requirements was to support the reliable operation of the Bulk Electric System (BES). These requirements were prescriptive, and meant to provide an industry-wide approach to achieving the reliability objectives of the standards. In the last 10 years, the industry has matured and adopted compliance through the Reliability Standards, and the continuance of the added granularity of the requirements do not contribute to the efficiency and effectiveness of Reliability Standards.

In 2010, NERC determined that absolute, "do exactly as the standard dictates" requirements, in some cases, did not satisfy the reliability goal and required the entity to perform specific actions to be compliant, while not effectively adding to the overall reliability goal. NERC then embarked on a shift in the standards paradigm to what is now known as 'results-based standards,' wherein the standards specify what reliability results from the requirements, while affording entities flexibility in achieving those results. The development guidance, provided by NERC, can be found at the following link:

https://www.nerc.com/pa/Stand/Resources/Documents/Results-Based_Reliability_Standard_Development_Guidance.pdf

Many of the requirements that the Project 2018-03 SDT are proposing to retire in this project pre-date the maturity of the results-based standards paradigm. As a result, those requirements are overly prescriptive and often express the same obligation in several standards and requirements.

Purpose:~~intended to facilitate~~

The purpose of the Technical Justification Document is to assist in the understanding ~~about~~of the technical rationale ~~for~~ associated with each recommendation ~~proposed by~~for retirement identified in the ~~SDT.~~ SAR.

Technical Justifications for Phase I of Project 2018-03 Standards Efficiency Review - Retirements

BAL-005-1, Requirements R4 and R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain

Rationale
The SDT ~~believes~~determined these requirements should be retained for the following reasons:

Requirements R4 and R6 of BAL-005-1 are requirements specific to the calculation of the Area Control Error (ACE). TOP-010-1(i) Requirement R2 covers ACE with the wording of "…analysis functions and Real-time monitoring…" but does not cover specifics, such as: quality flags for missing or invalid data that is part of BAL-005-1, Requirement R4, or the accuracy of scan rates that is part of BAL-005-1, Requirement R6.

In TOP-010-1(i), Requirement R2 (revised from TOP-010-1) covers the calculation and monitoring of ACE~~,~~; however, the language: "Each Balancing Authority (BA) shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring," is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) Requirement R4 states: "The ~~Balancing Authority~~BA shall make available to the operator information associated with ~~Reporting~~reporting ACE including, but not limited to, quality flags indicating missing or invalid data." Requirement R6 of BAL-005-1 states: "Each ~~Balancing Authority~~BA that is within a multiple ~~Balancing Authority~~BA Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each ~~Balancing Authority Area."~~BA area." Both of these requirements are specific to identifying missing or invalid data plus scan rates, not just the quality of the Real-time data.

The ~~Standards Efficiency Review – Retirements (~~SER Phase I~~)~~ team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirements R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i), Requirement R2, that would satisfy the missing or invalid data plus scan rates. If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be ~~able to be looked at~~candidates for retirement within that project or ~~within~~ a future project.

COM-002-4, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding, and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005-2 would not meet the NERC Board of Trustees (BOT) November 7, 2013 Resolution to mandate training, that the SDT ~~included~~include a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity, and any subsequent training can be covered in PER-005-2, or through the operator feedback loop as determined by the entity.

The SER Phase I team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2, Requirement R2 that would satisfy the training requirements specific to training on communications protocols. If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations, and then finds that there is that opportunity, then Requirement R2 of COM-002-4 may be ~~able to be looked at~~a candidate for retirement within that project or ~~within~~ a future project.

EOP-005-3, Requirement R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes~~,~~; however, it is does not specifically provide for ~~system~~System restoration training. In PER-005-2, the requirement to provide ~~system~~System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to ~~system~~System restoration from PER-005-1 was, in part, based on the existence of the former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide ~~system~~System restoration training to operating personnel in any of the ~~standards~~Reliability Standards.

A specific requirement for ~~system~~System restoration training should be maintained because, while a ~~system~~System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirement R8 of EOP-005-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to ~~system~~System restoration training. If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R8 of EOP-005-3 may be ~~able to be looked at~~a candidate for retirement within that project or ~~within~~ a future project.

EOP-006-3, Requirement R7
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

The PER-005-2 standard entails training processes~~,~~; however, it is does not specifically provide for ~~system~~System restoration training. In PER-005-2, the requirement to provide ~~system~~System restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to ~~system~~System restoration from PER-005-1 was, in part, based on the existence of former Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R7 in EOP-006-3 is removed, then there will not be any requirements to provide ~~system~~System restoration training to operating personnel in any of the ~~standards~~Reliability Standards.

A specific requirement for ~~system~~System restoration training should be maintained because, while a ~~system shutdown is a low probability, it could have a high impact if not done properly. A specific requirement for system restoration training should be maintained because, while a system~~System shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirement R7 of EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to ~~system~~System restoration training. If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R7 of EOP-006-3 may be ~~able to be looked at~~a candidate for retirement within that project or~~ within~~ a future project.

FAC-008-3, Requirements R7 and R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined these requirements should be retired for the following reasons:

These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission ~~Provider~~Planners (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1, Requirement R2, the Transmission ~~Operator~~Owner (TO) and Generator ~~Operator~~Owner (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1, and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data ~~necessarily~~ includes facility ratings as inputs to System Operating Limits (SOL) monitoring. IRO-010-2, Requirement R3, and TOP-003-3, Requirement R5, require that the TO and the GO to respond to the RC's and the TOP's requests.

FAC-013-2 Requirements R1, R2, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale

The SDT ~~believes~~determined this standard should be retired for the following reasons:

The requirement for ~~Planning Coordinators (PC)~~PCs to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Individual PCs develop their own methodologies that may be ~~very~~ disparate from each other.
- Impacted functional entities, such as the TP, do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable ~~system~~System performance is.
- Entities that receive the methodology or assessment results are not obligated to use or ~~even~~ consider the information in their assessments.
- Requirement R4 only requires the assessment ~~to~~ be performed for one year in the Near-Term Transmission Planning Horizon. ~~This year~~The PC can ~~be~~ arbitrarily ~~chosen by the PC~~choose this year, and the analysis does not guarantee transmission service that is necessary for System reliability.

Assessing transfer capability in the planning horizon is a method to test the robustness of the ~~system~~System. Robustness testing of a ~~system~~System is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment of it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by ~~FERC~~the Federal Energy Regulatory Commission (FERC) in 2014.

INT-004-3.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale

The SDT ~~believes~~determined this standard should be retired for the following reasons:

INT-004-3.1 may be retired since it satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice.' Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity~~,~~ (PSE), has been removed from the list of NERC Functional Entities, supporting the market-based observations herein. Requirement R3 specifically refers to “Pseudo-Ties that are included in the ~~NAESB~~North American Energy Standards Board (NAESB) Electric Industry Registry,” reinforcing the tie to ~~North American Energy Standards Board (NAESB)~~the NAESB Wholesale Electric Quadrant (WEQ) Business Practice Standards.

INT-006-4, Requirements R3.1, R4, and R5
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined these requirements should be retired for the following reasons:

INT-006-4, Requirement R3 Part 3.1 can be retired under Paragraph 81, Criterion A. There is no substantive impact on reliability with requiring the RC to be notified when a Reliability Adjustment Arranged Interchange has been denied.

INT-006-4, Requirement R4 can be retired under Paragraph 81, Criteria A and B7. Covered in ~~North American Energy Standards Board (~~NAESB~~)~~ e-Tagging specifications, Section 1.6.3.1 and Section 1.3, Request State. This requirement outlines the conditions that must exist for an Arranged Interchange to transition to Confirmed Interchange. NAESB Electronic Tagging Specification Section 1.6.3.1 and Section 1.3, Request State, stipulate these exact requirements. INT-006-4, Requirement R4 is being recommended for retirement~~, the~~. The requirement is accomplished through a ~~Balancing Authority's (BA)~~BA's e-Tag Authority Service and does not have an impact on reliability.

INT-006-4, Requirement R5 can be retired under Paragraph 81, Criteria A and B7. This is covered in NAESB e-Tagging specifications, Section 1.6.4. This requirement outlines who is notified when the transition to Confirmed Interchange occurs. NAESB Electronic Tagging Specification, Section 1.6.4, stipulate these exact requirements. INT-006-4, Requirement R5, is being recommended for retirement~~,~~; the requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-009-2.1, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined this requirement should be retired for the following reasons:

This requirement can be retired under Paragraph 81, Criterion B7~~, as the requirement~~. INT-009-2.1, Requirement R2, is redundant with the approved NERC Reliability Standard BAL-005-1, Requirement R7.

INT-010-2.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined this standard should be retired for the following reasons:

The opportunity exists to retire Reliability Standard INT-010-2.1 in its entirety.

INT-010-2.1, Requirement R1: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R1 for retirement. More stringent tagging requirements already

exist in NAESB WEQ-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the ~~Bulk Electric System (BES).~~BES.

INT-010-2.1, Requirement R2: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended INT-010-2.1 Requirement R2 for retirement. More stringent tagging requirements already exist in NAESB WEQ~~-~~-004-8. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R3: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also ~~recommendation~~recommended INT-010-2.1 Requirement R3 for retirement. More stringent tagging requirements already exist in NAESB WEQ~~-~~-004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5, Requirements R1, R4 and R6:
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R1, Retain Requirements R4 and R6
Rationale
The SDT ~~believes~~determined that Requirement R1 should be retired for the following reasons:

Requirement R1 of IRO-002-5 is redundant to other requirements in the Interconnection Reliability Operations and Coordination (IRO) family of standards. Requirement R1 and data exchange for the Operational Planning Assessment (OPA) is inherent to Requirement R2 that has a higher Violation Risk Factor (VRF) and is tied to the OPA in IRO-010-2, Requirement R3. The requirement is a control for aiding compliance with IRO-008-2, Requirement R1, related to the performance of an ~~Operational Planning Analysis (OPA),~~OPA, and it is duplicative to Requirement R3 in IRO-010-2. The purpose statement of IRO-010-2 is ~~to ensure adequate data is collected so that~~ for the RC: "To prevent instability, uncontrolled separation, or Cascading outages the adversely impact reliability ~~is not adversely impacted~~, by ~~preventing instability, uncontrolled separation, or Cascading outages and is applicable to all functional entities in the RC area.~~ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area." The ~~purpose~~Purpose statement of IRO-008-2 is for the RC to ~~perform~~: "Perform the analysis to prevent instability, uncontrolled separation, or Cascading" and with the data collected per IRO-010-2. The data exchange capabilities are indicated in IRO-010-2, Requirement R3, which includes ~~BAs~~BA's and TOPs, and IRO-008-2, Requirement R1, requires the RC to perform the OPA, which makes IRO-002-5, Requirement R1, redundant with the aforementioned standards and requirements.

~~IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to comply with IRO-010-2, Requirement R3, it must be able to exchange data with the requesting RC.~~IRO-010-2 (R1) requires the RC to identify the data it needs to perform its OPA's, Real-time monitoring, and Real-time Assessments. Requirement R1 clearly states what is required, 1.1 A list of data and information needed by the RC to support its OPA, Real-time monitoring, and Real-time assessments including non-BES data and external network data, as deemed necessary by the RC, 1.2 Provisions for notification of current Protection System and Special Protection Systems status or degradation that impacts System Reliability, 1.3 A periodicity for providing data, 1.4 The deadline by which the respondent is to provide the indicated data. Requirement R2 clearly states, “The RC shall distribute its data specifications to entities that have data required by the RC’s OPAs, Real-time monitoring, and Real-time Assessments. Requirement R3 gets to the core of the data exchange capabilities “Each RC, BA, GO, GOP, Load-Serving Entity (LSE), TOP, TO, and Distribution Provider (DP) receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using 3.1 A mutually agreeable format, 3.2 A mutually agreeable process for resolving data conflicts, 3.3 A mutually agreeable security protocol. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the OPA. Finally, Measure M1 for IRO-002-5, Requirement R1, states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the IRO-002-5, Requirement R1, is not needed to support reliability and can be retired.

The SDT ~~believes~~determined that Requirements R4 and R6 should be retained for the following reasons:

IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

~~Requirement R4 of IRO-002-5 needs to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), Internet Technology (IT), or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (cf. IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. In addition, RC equipment outages are not required to follow the RC’s outage coordination process (i.e., IRO-017-1, Requirement R2 is only applicable to TOPs and BAs). As such, a potential gap in the standards would exist if IRO-002-5, Requirement R4 was retired.~~
The requirements in IRO-010-2 shall satisfy the obligations of identifying the data required and means for delivering the data for the Operational Planning Analysis Real-time monitoring, and Real-time Assessments. This data exchange is accomplished via a redundant/secure communications, such as Inter Control Center Communication Protocol (ICCP), email, voltage schedules, outage scheduling that all RCs, BAs and TOPs use to exchange the required data.

IRO-008-2, Requirement R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

Although IRO-008-2, Requirement R6, appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6, is not being sought during this phase of the project.

IRO-014-3, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (Requirement R1, Part 1.1~~),~~); this ensures RC operations are coordinated to maintain reliability of the BES. As such, a separate requirement for ensuring notifications are made to impacted RCs is duplicative. However, the IRO-014-3, Requirement R1, time horizon would need to be revised to a time horizon of "Real-time" if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3, is not being sought during this phase of the project.

The SER Phase I team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirement R3 of IRO-014-3 to determine if there is opportunity for revision to IRO-014-3, Requirement R1, that would satisfy the revision of the time horizon to "Real-time." If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R3 of IRO-014-3 may be ~~able to be looked at~~a candidate for retirement within that project or within a future project.

IRO-017-1, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this requirement should be retained for the following reasons:

IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3, for retirement.

The SER Phase I team will communicate with the ~~Standards Efficiency Review~~SER Phase II team regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TLP-001-4 that would satisfy the adding of the RC as a named recipient. If the ~~Standards Efficiency Review~~SER Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R3 of IRO-017-1 may be ~~able to be looked at~~a candidate for retirement within that project or within a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3, MOD-001-1a and proposed MOD-001-2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined these standards should be retired for the following reasons:

Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as ~~eTags~~e-Tags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time ~~system~~System operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the ~~system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."~~System to its actual reliability limits.

MOD-002-1: Entities are not required to determine Total Flowgate Capability (TFC), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), Available Transfer Capability (ATC), Capacity Benefit Margin (CBM), or Transmission Reliability Margin (TRM), therefore; this is a conditional obligation, and there is no requirement that entities coordinate their methodologies. A reliability-based requirement

would establish obligations to ensure consistency between entities' methodologies. These requirements are administrative in nature and have no performance measure.

Additionally, TOPs and/or TSPs are not obligated in any fashion to determine TFC, TTC, AFC, ATC, CBM or TRM, nor are any criteria established for these quantities. Therefore, the requirements here require that entities that use an optional mechanism with no related criteria provide a methodology document and associated implementation documents, with no criteria as to what those documents must include, rather than just their "methodology." That reinforces that these are all administrative documents with little (if any) reliability benefit.

Further, Requirement R3 establishes that the TSP develops CBM for the benefit of the LSE, which has been removed from the list of NERC Functional Entities.

Finally, Requirements R5 and R6, through their clear and focused references to Open Access Same-Time Information System (OASIS), further emphasize the commercial elements of these subjects, and that this information, shared with other market participants, may easily be subject to FERC transparency rules commonly known as FERC Standards of Conduct under Rule 888. The definition of AFC also explicitly contains the term, "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." This seems to leave little question about the market focus of particularly Flowgate Capability.

MOD-020-0, Requirement R1 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined this standard should be retired for the following reasons:

MOD-031-2 and IRO-010-2 do not give the necessary entities the authority to request relevant information, nor does MOD-031-2 and IRO-010-2 require the associated entities to provide that information. Demand-Side Management (DSM) data ~~is necessarily~~may be related to the near-term operating time horizon~~, as well as~~ and/or the planning time horizons, but not to the Real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4, Requirements R1 and R2, and IRO-001-4, Requirement R1, the RC, BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over DSM. ~~-~~They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4, Requirement R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0, Requirement R1, are sources of DADS data, have access to DADS data, or both.

DSM and Direct Control Load Management (DLCM) may be regarded as long-term~~-~~ planning and operations~~-~~ planning time horizon resources, but~~,~~ particularly with a "on request within 30 calendar days" obligation in the requirement, is not a resource for the Real-time or day-ahead operating time horizon for ~~Reliability Coordinators~~RCs and ~~Transmission Operators~~TOPs, which must plan to operate, and actually operate, the BES within ~~SOLs~~SOL's and ~~IROLs~~IROL's, a subset of SOLs. In addition, the amount of interruptible demands and DLCM at the TP, Resource Planner (RP), and/or ~~Load-Serving Entity (~~LSE~~)~~ (which has been removed from the compliance registry and is no longer obligated to comply with NERC standards) level is not of locational benefit to TOPs and RCs to assist them in operating within ~~SOLs~~SOL's, as such information, were it to be provided within a usable time frame, would not be sufficiently granular to assist the TOP and RC. All meaningful information regarding interruptible demands and DLCM is available from DADS, which~~,~~ in the United States~~,~~ (US), is a mandatory reporting mechanism, regulated per Section 1600 of the NERC Rules of Procedure. DSM and DLCM are financially-enabled mechanisms whereupon RPs may encourage customers and customer groups to permit local control of their load in exchange for rate considerations~~. And~~, and this local control may or may not be sited in such a manner to provide any benefit to ~~TOPs~~TOP's and ~~RCs~~RC's; which, again, are obligated by NERC Standards to operate the BES within ~~SOLs~~SOL's.

PRC-004-5(i), Requirement R4
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT ~~believes~~determined this requirement should be retired for the following reasons:

The standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for BES Elements. The Reliability Standard's Guideline and Technical Basis for Requirement R4 considers due diligence that an entity must make in determining the cause of a Protection System Misoperation.

The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with Requirements R1 and R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a Misoperation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation, and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of Requirement R4 does not preclude the entity's responsibility to continue the investigation to identify the cause of ~~Misoperation. However~~Misoperations; however, it does alleviate the need to keep tracking documents for ~~the sake of~~ showing investigative actions.

PRC-015-1 Requirements R1, R2, and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this standard should be retained for the following reasons:

PRC-015-1 is scheduled to be retired on 12/31/2020 under the PRC-012-2 Implementation Plan (IP).

PRC-018-1 Requirements R1, R2, R3, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT ~~believes~~determined this standard should be retained for the following reasons:

PRC-018-1 is superseded by PRC-002-2 in Year 2022. The PRC-002-2 IP states: "Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2…"

TOP-001-4 Requirements R16, R17, R19 and R22
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain Requirements R16 and R17, Retire Requirements R19 and R22
Rationale
The SDT ~~believes~~determined Requirements R16 and R17 should be retained for the following reasons:

Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator (SO) has authority to postpone, cancel or recall planned outages of Energy Management System (EMS~~,~~), IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17, were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17, is not being sought during this phase of the project.

The ~~Purpose~~purpose of TOP-003-3 is to ensure adequate data is collected by the BA and TOP to fulfill their operational and planning responsibilities. The ~~Purpose~~purpose of TOP-002-4 is to ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22, for the BA and TOP are redundant with TOP-003-3, Requirements R3, R4 and R5, and TOP-002-4, Requirement R1.

The SDT ~~believes~~determined Requirements R19 and R22 should be retired for the following reasons:

TOP-001-4, Requirement R19, is redundant to other requirements in the Transmission Operations (TOP) family of standards. For TOPs, the existing TOP-003-3, Requirement R5, cannot be fulfilled by entities unless data exchange capabilities exist between the TOP and the supplying entities. Similarly, TOP-002-4, Requirement R1, cannot be fulfilled by the TOP unless the data needed to perform the OPA has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R19 in TOP-001-4 is not needed to support reliability and can be retired.

TOP-001-4, Requirement R22~~,~~ is redundant to other requirements in the TOP family of standards. For the BA, the existing TOP-003-3, Requirement R5~~,~~ cannot be fulfilled by entities unless data exchange capabilities exist between the BA and the supplying entities. Similarly, TOP-002-4, Requirement R4 cannot be fulfilled by the BA unless the data needed to develop its Operating Plan for next-day operations has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R22 in TOP-001-4 is not needed to support reliability and can be retired.

VAR-001-5*, Requirements R2 and R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R2, Retain Requirement R3
Rationale
The SDT ~~believes~~determined Requirement R2 should be retired for the following reasons:

VAR-001-5, Requirement R2 ~~is duplicative~~states, "Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load"

VAR-001-5, Requirement R2, contains two sentences, with the ~~existing requirements in~~ first sentence being a requirement and the ~~TOP-001-4 and TOP-002-4, which direct~~ second being a guidance statement. Each sentence is analyzed separately.

The first sentence requires the TOP to ~~plan and~~ schedule sufficient reactive resources to regulate voltage levels under normal and contingency conditions. By using the OPA as described and required in TOP-002-4 and the criteria described in TOP-001-4, Requirement R10, the TOP must use a variety of tools to regulate voltage levels, including reactive control. Using Real-time Contingency Analysis (RTCA) tools allows the TOP to determine specific actions to regulate voltage during contingency conditions. Additionally, the TOP uses Real-time monitoring, allowing it to make real-time decisions on voltage during normal conditions. These allow the TOP to quantify the use of reactive resources and makes VAR-001-5, Requirement R2, unnecessary.

Further to this requirement that a TOP have sufficient reactive resources, the planning standard TPL-001-4 requires the PA and TP to conduct studies on their transmission Systems to ensure it operates reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. These studies include available reactive resource capabilities. The studies provide corrective action plans (CAPs) when the analysis indicates an inability of the System to meet performance requirements. CAPs include, as necessary, the amount of reactive resource capabilities needed. This ensures that the TOP has available an adequate number of reactive resources to operate ~~within in SOL values, which includes system voltage limits. TOP~~under normal contingency conditions.

TOP-002-4, Requirement R1~~,~~ requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10~~,~~ provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. The requirements in TOP-001-4 and TOP-002-4 ~~requirements~~ direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-~~4.2~~5 requirements ~~ensure~~mandate that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. ~~The FAC~~The Facilities Design, Connections and Maintenance (FAC) family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and ~~system~~System ratings.

Specifically,

1. TOP-002-4~~,~~ - Operations Planning with an effective date of April 1, 2017

   Requirement R1 ~~thus~~of this standard requires the TOP to have an OPA that will allow it to assess whether its ~~next-day~~ planned operations for the next day within its Transmission Operator Area will exceed any ~~SOLs, and TOP-001-4,~~of its SOL's. Requirement ~~R10 thus~~R2 requires ~~that the TOP monitor its Facilities and thus determine~~the TOP to have an Operating Plan(s) for next-day operations to address potential SOL exceedances~~. Further, TOP-001-4,~~ identified as a result of its OPA as required in Requirement R1.

   An Operating Plan is defined by NERC as "*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific System restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*"

   In order to mitigate SOL exceedances, or to address potential SOL exceedances, the TOP must have a variety of tools available to immediately address such condition; one such tool is reactive resources. The TOP must have an adequate number of reactive resources to mitigate any potential or actual SOL exceedance. The adequate or sufficient number is determined through analysis.

2. TOP-001-4 – Transmission Operations with an effective date of July 1, 2018

   Requirement R13 requires each TOP to ensure a Real-time Assessment is performed at least once every 30 minutes, and Requirement R14 requires ~~that~~ the TOP ~~"…~~to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment~~…" and TOP-001-4, Requirement R1 requires that the TOP "…shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions."~~ .

~~Since operating outside voltage limits represents a SOL exceedance, the TOP must have an OPA that assesses whether its next-day operations will exceed SOLs. The TOP has the obligation to initiate an Operating Plan to mitigate an SOL exceedance, and has the responsibility to take any actions under its control and issue Operating Instructions, if needed. The responsibilities elucidated in VAR-001-4.1, Requirement R2 are fully addressed in these other standards; scheduling sufficient reactive resources to~~

~~regulate voltage levels under normal and Contingency conditions is one of several vital elements of addressing this obligation.~~

> This requirement, again, addresses that the TOP have an Operating Plan to mitigate SOL exceedances. The same requirement of TOP exists here as it did under TOP-002-4; the TOP must have an adequate number of reactive resources to mitigate SOL exceedances. The adequate or sufficient number is determined through analysis.

The second sentence of VAR-001-5 R2 states: “Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.” As noted by the VAR Enhanced Periodic Review group during its September 2016 meeting, and agreed to herein, this language is guidance or a measure and is unnecessary in the requirement. It was suggested then, as well as now, that perhaps this language be moved to a guidance section or document.

The SDT ~~believes~~determined that Requirement R3 should be retained for the following reasons:
For reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL to prevent voltage-collapse events wherein the operation within SOLs/IROLs itself is not adequate to assure stable voltage operations in both steady-state and transient conditions. The TOP~~-series~~ family of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary.

* VAR-001-4.2~~,~~ is an inactive standard. VAR-001-5 changed the Western Electricity Coordinating Council (WECC) variance, and not the continent-~~-~~wide requirements. VAR-001-5 became effective January 1, 2019.

Standards Announcement

Project 2018-03 Standards Efficiency Review Retirements

Final Ballots Open through May 2, 2019

Now Available

10-day final ballots for the **Project 2018-03 Standards Efficiency Review Retirements** are open through **8 p.m. Eastern, Thursday, May 2, 2019.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. 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 ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pools associated with this project can log in and submit their vote 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).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results 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 Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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: 2018-03 Standards Efficiency Review Retirements FAC-008-4 FN 2 ST
Voting Start Date: 4/23/2019 10:16:38 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 286
Total Ballot Pool: 317
Quorum: 90.22
Quorum Established Date: 4/23/2019 11:55:07 AM
Weighted Segment Value: 95.74

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	85	1	69	1	0	0	0	6	10
Segment: 2	8	0.7	6	0.6	1	0.1	0	1	0
Segment: 3	71	1	60	1	0	0	0	4	7
Segment: 4	15	1	12	0.923	1	0.077	0	0	2
Segment: 5	74	1	64	1	0	0	0	2	8
Segment: 6	54	1	50	1	0	0	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
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	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	317	6.5	268	6.223	3	0.277	0	15	31

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Negative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham	Joseph Amato	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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 Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Abstain	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 317 of 317 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements FAC-013-2 FN 2 ST
Voting Start Date: 4/23/2019 10:35:48 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 272
Total Ballot Pool: 299
Quorum: 90.97
Quorum Established Date: 4/23/2019 12:24:34 PM
Weighted Segment Value: 97.66

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	79	1	63	0.984	1	0.016	0	6	9
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	56	0.982	1	0.018	0	5	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	68	1	59	0.983	1	0.017	0	2	6
Segment: 6	53	1	46	0.979	1	0.021	0	2	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	299	6.6	251	6.446	5	0.154	0	16	27

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	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	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 299 of 299 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-004-3.1 FN 2 ST
Voting Start Date: 4/23/2019 10:36:37 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 268
Total Ballot Pool: 295
Quorum: 90.85
Quorum Established Date: 4/23/2019 12:25:17 PM
Weighted Segment Value: 95.94

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	76	1	61	0.968	2	0.032	0	4	9
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	53	0.946	3	0.054	0	5	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	68	1	57	0.966	2	0.034	0	3	6
Segment: 6	53	1	43	0.935	3	0.065	0	3	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	295	6.6	241	6.332	11	0.268	0	16	27

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		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		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 295 of 295 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-006-5 FN 2 ST
Voting Start Date: 4/23/2019 10:23:00 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 271
Total Ballot Pool: 298
Quorum: 90.94
Quorum Established Date: 4/23/2019 12:22:01 PM
Weighted Segment Value: 96.64

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	77	1	60	0.952	3	0.048	0	5	9
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	55	0.965	2	0.035	0	4	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	69	1	60	0.984	1	0.016	0	2	6
Segment: 6	53	1	45	0.957	2	0.043	0	2	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	7	0.6	6	0.6	0	0	0	1	0
Totals:	298	6.7	248	6.475	9	0.225	0	14	27

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		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	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	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	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 298 of 298 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-009-3 FN 2 ST
Voting Start Date: 4/23/2019 10:24:03 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 271
Total Ballot Pool: 298
Quorum: 90.94
Quorum Established Date: 4/23/2019 12:22:12 PM
Weighted Segment Value: 97.22

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	77	1	62	1	0	0	0	6	9
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	68	1	55	1	0	0	0	6	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	69	1	59	1	0	0	0	4	6
Segment: 6	53	1	46	1	0	0	0	3	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	298	6.6	248	6.417	2	0.183	0	21	27

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		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	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Abstain	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	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	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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		Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements INT-010-2.1 FN 2 ST
Voting Start Date: 4/23/2019 10:37:32 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 269
Total Ballot Pool: 296
Quorum: 90.88
Quorum Established Date: 4/23/2019 12:25:03 PM
Weighted Segment Value: 90.19

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	76	1	60	0.968	2	0.032	0	5	9
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	53	0.964	2	0.036	0	6	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	69	1	55	0.948	3	0.052	0	5	6
Segment: 6	53	1	44	0.957	2	0.043	0	3	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
Segment: 9	1	0.1	0	0	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	6	0.5	4	0.4	1	0.1	0	1	0
Totals:	296	6.6	235	5.953	14	0.647	0	20	27

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Negative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Abstain	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		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	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	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	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	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		Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 296 of 296 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements IRO-002-6 FN 2 ST
Voting Start Date: 4/23/2019 10:26:47 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 270
Total Ballot Pool: 298
Quorum: 90.6
Quorum Established Date: 4/23/2019 12:22:24 PM
Weighted Segment Value: 97.19

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	78	1	61	1	0	0	0	8	9
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	68	1	53	1	0	0	0	8	7
Segment: 4	13	1	10	0.909	1	0.091	0	1	1
Segment: 5	68	1	58	1	0	0	0	3	7
Segment: 6	53	1	43	1	0	0	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	298	6.8	242	6.609	2	0.191	0	26	28

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Abstain	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		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Abstain	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Abstain	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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 298 of 298 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-001-1a FN 2 ST
Voting Start Date: 4/23/2019 10:38:22 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 278
Total Ballot Pool: 308
Quorum: 90.26
Quorum Established Date: 4/23/2019 12:25:31 PM
Weighted Segment Value: 95.47

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	83	1	67	0.957	3	0.043	0	3	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	58	0.951	3	0.049	0	2	7
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	71	1	60	0.938	4	0.063	0	0	7
Segment: 6	53	1	46	0.939	3	0.061	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	308	6.6	258	6.301	14	0.299	0	6	30

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	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		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 308 of 308 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-001-2 FN 2 ST
Voting Start Date: 4/23/2019 10:45:48 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 274
Total Ballot Pool: 303
Quorum: 90.43
Quorum Established Date: 4/23/2019 12:27:12 PM
Weighted Segment Value: 94.63

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	82	1	65	0.942	4	0.058	0	3	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	56	0.933	4	0.067	0	2	7
Segment: 4	13	1	11	0.917	1	0.083	0	0	1
Segment: 5	69	1	58	0.935	4	0.065	0	0	7
Segment: 6	53	1	45	0.918	4	0.082	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	303	6.6	251	6.246	17	0.354	0	6	29

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	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		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	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	Jennifer Hohenshilt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 303 of 303 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-004-1 FN 2 ST
Voting Start Date: 4/23/2019 10:39:07 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 280
Total Ballot Pool: 310
Quorum: 90.32
Quorum Established Date: 4/23/2019 11:56:03 AM
Weighted Segment Value: 94.34

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	82	1	66	0.957	3	0.043	0	3	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	58	0.951	3	0.049	0	2	7
Segment: 4	16	1	12	0.857	2	0.143	0	0	2
Segment: 5	71	1	59	0.922	5	0.078	0	0	7
Segment: 6	54	1	47	0.94	3	0.06	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	310	6.6	258	6.226	16	0.374	0	6	30

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	Negative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	Negative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		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	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	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	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 310 of 310 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-008-1 FN 2 ST
Voting Start Date: 4/23/2019 10:39:48 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 278
Total Ballot Pool: 308
Quorum: 90.26
Quorum Established Date: 4/23/2019 12:25:58 PM
Weighted Segment Value: 94.69

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	83	1	66	0.943	4	0.057	0	3	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	70	1	57	0.934	4	0.066	0	2	7
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	71	1	60	0.938	4	0.063	0	0	7
Segment: 6	53	1	45	0.918	4	0.082	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	308	6.6	255	6.25	17	0.35	0	6	30

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	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		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 308 of 308 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-020-0 FN 2 ST
Voting Start Date: 4/23/2019 10:40:38 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 281
Total Ballot Pool: 310
Quorum: 90.65
Quorum Established Date: 4/23/2019 11:56:57 AM
Weighted Segment Value: 96.59

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	83	1	68	0.986	1	0.014	0	4	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	59	0.983	1	0.017	0	2	7
Segment: 4	15	1	12	0.857	2	0.143	0	0	1
Segment: 5	72	1	63	0.969	2	0.031	0	0	7
Segment: 6	54	1	49	0.98	1	0.02	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	310	6.6	267	6.375	7	0.225	0	7	29

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		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	Andy Fuhrman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	Negative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	Negative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Showing 1 to 310 of 310 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-028-2 FN 2 ST
Voting Start Date: 4/23/2019 10:42:44 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 274
Total Ballot Pool: 304
Quorum: 90.13
Quorum Established Date: 4/23/2019 12:26:22 PM
Weighted Segment Value: 95.28

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	81	1	64	0.955	3	0.045	0	4	10
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	70	1	58	0.951	3	0.049	0	2	7
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	70	1	59	0.937	4	0.063	0	0	7
Segment: 6	53	1	46	0.939	3	0.061	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	5	0.4	4	0.4	0	0	0	1	0
Totals:	304	6.4	252	6.098	14	0.302	0	8	30

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	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	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		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	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 304 of 304 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-029-2a FN 2 ST
Voting Start Date: 4/23/2019 10:43:45 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 274
Total Ballot Pool: 304
Quorum: 90.13
Quorum Established Date: 4/23/2019 12:26:47 PM
Weighted Segment Value: 95.41

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	81	1	64	0.955	3	0.045	0	4	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	69	1	57	0.95	3	0.05	0	2	7
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	70	1	59	0.937	4	0.063	0	0	7
Segment: 6	53	1	46	0.939	3	0.061	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	304	6.6	253	6.297	14	0.303	0	7	30

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	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.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	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	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	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	Jennifer Hohenshilt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 304 of 304 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements MOD-030-3 FN 2 ST
Voting Start Date: 4/23/2019 10:45:03 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 274
Total Ballot Pool: 305
Quorum: 89.84
Quorum Established Date: 4/23/2019 12:26:59 PM
Weighted Segment Value: 94.55

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	82	1	65	0.942	4	0.058	0	3	10
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	69	1	56	0.933	4	0.067	0	2	7
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	70	1	58	0.935	4	0.065	0	0	8
Segment: 6	53	1	45	0.918	4	0.082	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	6	0.5	5	0.5	0	0	0	1	0
Totals:	305	6.5	250	6.146	17	0.354	0	7	31

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		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	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		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	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	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		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	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		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		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	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		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	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Negative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 305 of 305 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements PRC-004-6 FN 2 ST
Voting Start Date: 4/23/2019 10:28:14 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 290
Total Ballot Pool: 322
Quorum: 90.06
Quorum Established Date: 4/23/2019 11:55:22 AM
Weighted Segment Value: 87.12

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	85	1	67	0.931	5	0.069	0	3	10
Segment: 2	8	0.7	6	0.6	1	0.1	0	1	0
Segment: 3	72	1	58	0.921	5	0.079	0	2	7
Segment: 4	18	1	14	0.933	1	0.067	0	0	3
Segment: 5	75	1	62	0.925	5	0.075	0	0	8
Segment: 6	54	1	47	0.94	3	0.06	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0
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	7	0.6	3	0.3	3	0.3	0	1	0
Totals:	322	6.6	259	5.75	24	0.85	0	7	32

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Negative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Negative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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 Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Negative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Rutherford EMC	Tom Haire		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		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		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Negative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Missouri River Energy Services	Gerald Tielke		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 322 of 322 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements TOP-001-5 FN 2 ST
Voting Start Date: 4/23/2019 10:33:41 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 289
Total Ballot Pool: 321
Quorum: 90.03
Quorum Established Date: 4/23/2019 12:22:39 PM
Weighted Segment Value: 97.75

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	85	1	69	0.972	2	0.028	0	4	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	74	1	62	0.984	1	0.016	0	3	8
Segment: 4	16	1	13	0.929	1	0.071	0	0	2
Segment: 5	75	1	66	0.985	1	0.015	0	0	8
Segment: 6	53	1	48	0.98	1	0.02	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	7	0.6	6	0.6	0	0	0	1	0
Totals:	321	6.7	275	6.549	6	0.151	0	8	32

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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 Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Kagen DelRio	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Kagen DelRio	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		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		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Kagen DelRio	Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		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	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 321 of 321 entries

BALLOT RESULTS

Ballot Name: 2018-03 Standards Efficiency Review Retirements VAR-001-6 FN 2 ST
Voting Start Date: 4/23/2019 10:35:03 AM
Voting End Date: 5/2/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 283
Total Ballot Pool: 316
Quorum: 89.56
Quorum Established Date: 4/23/2019 12:22:55 PM
Weighted Segment Value: 96.57

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	85	1	68	0.958	3	0.042	0	4	10
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	71	1	59	0.967	2	0.033	0	2	8
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	75	1	64	0.97	2	0.03	0	0	9
Segment: 6	53	1	47	0.959	2	0.041	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
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	7	0.6	6	0.6	0	0	0	1	0
Totals:	316	6.7	266	6.471	10	0.229	0	7	33

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matthew Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	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		None	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Lee Maurer		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		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	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	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.	David Zwergel		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	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	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	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		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
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 Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Maurice Paulk	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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	Sharon Flannery		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Imperial Irrigation District	Denise Sanchez		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	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		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	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	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		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	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan	Robin Hill	Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Marcus Moor	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	MGE Energy - Madison Gas and Electric Co.	Steven Schultz		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Marty Hostler		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Richard Kinas		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
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	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	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	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	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	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	MGE Energy - Madison Gas and Electric Co.	Robert Thorson		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Thomas Savin		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 316 of 316 entries

Exhibit G

Standard Drafting Team Roster,

Project 2018-03 – Standards Efficiency Review Retirements

Standard Drafting Team Roster

Project 2018-03 Standards Efficiency Review Retirements

	Name	Entity
Chair	Charles Rogers	Consumers Energy
Vice Chair	Bob Staton	Public Service Company of Colorado (Xcel Energy)
Members	Karie Barczak	DTE Energy
	Sandeep Borkar	ERCOT
	Gerald Keenan	NWPP
	Mario Kiresich	Southern California Edison
	Thomas Leslie	Georgia Transmission Corp.
	Michael Steckelberg	Great River Energy
	Stephen Wendling	American Transmission Company
	Jim Williams	SPP
PMOS Liaisons	Michael Brytowski	Great River Energy
	Mark Pratt	Southern Company
NERC Staff	Laura Anderson – Standards Developer	North American Electric Reliability Corporation
	Darrel Richardson – Principal Technical Advisor	North American Electric Reliability Corporation
	Scott Barfield – Senior Technical Advisor	North American Electric Reliability Corporation
	Al McMeekin – Senior Technical Advisor	North American Electric Reliability Corporation
	Lauren Perotti – Counsel	North American Electric Reliability Corporation
	Wendy Muller – Specialist, Standards Development	North American Electric Reliability Corporation